AN ALTERNATIVE TO THE WINLAND R35 METHOD FOR DETERMINING CARBONATE RESERVOIR QUALITY

A Thesis

by

STÉPHANIE LAFAGE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2008

Major Subject: Geology

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Approved by:

Chair of Committee,	Wayne M. Ahr
Committee Members,	Yuefeng Sun
	Duane A. Mc Vay
Head of Department,	Andreas Kronenberg

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ABSTRACT

An Alternative to the Winland R35 Method for

Determining Carbonate Reservoir Quality. (August 2008)

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Chair of Advisory Committee: Dr Wayne M. Ahr

This study evaluates the applicability of the Winland R35 method as a means to assess reservoir quality in carbonate reservoirs.

The Winland R35 method [Log R35 = 0.732 + 0.588 (Log K_{air}) – 0.864 (Log Φ)] is based on the relationship between porosity, permeability, and pore throat radius at the point of 35% mercury saturation in capillary pressure measurements and is generally reliable in rocks with only intergranular porosity (such as sandstone) where pore and pore throat geometry are related closely to rock texture. Carbonate pores are not always so; consequently, the Winland method is not as reliable for assessing reservoir quality in carbonate reservoirs. To evaluate alternatives to the conventional Winland technique, based on rock facies characteristics, samples from the Jurassic Smackover Formation in Alabama and the Permian Clearfork Formation in Texas were tested for reservoir quality with use of the Winland R35 and Pittman methods to determine if either method is more reliable in carbonate reservoir studies.

Pittman's modification of the Winland method was found to be more accurate graphically. A third method for evaluating reservoir rock character is provided by Lucia. This method is based on geological rather than petrophysical characteristics, and it revealed that pore throat sizes at 35% mercury saturation may include a variety of depositional and diagenetic rock fabrics. The Winland and Pittman petrophysical evaluation techniques, as well as the Lucia geological evaluation technique - when based on depositional facies alone - do not provide reliable measures of reservoir quality. An alternative method based on genetic pore type presented by Ahr in 2005 was tested for comparison. Using a porosity–permeability plot based on the pore type, the relationship between porosity, permeability, and pore type was found to be strong and reproducible. When the ratio of permeability to porosity was used in combination with Ahr genetic pore types, the results indicate that barriers, baffles, and flow units can be reliably defined. This study demonstrates that the use of pore types in conjunction with capillary pressure measurements is a more reliable method for evaluating carbonate reservoirs than any alternative method that is based on depositional facies or rock fabrics alone.

DEDICATION

To my grandmother, who left too soon

Pour ma grand-mère, partie un peu trop tôt

ACKNOWLEDGMENTS

First, I would like to express my greatest respect and appreciation to my advisor, Dr. Wayne M. Ahr, for supervising this thesis project throughout its development, for his excellent guidance, and for his dependability whenever help was needed.

I also wish to thank Drs. Yuefeng Sun and Duane A. McVay for serving on my committee.

I am very thankful to IFP School and the Tuck Foundation (especially Alain Mascle and Valérie Vedrenne) and the Texas A&M Geology Department for providing part of the funding for my studies here at Texas A&M University.

I must give many thanks to Dr. Tchakerian, head of the Geosciences College, Dr. Kronenberg, head of the Geology and Geophysics Department, and the OGS Staff for their help and understanding.

My sincere thanks go to my parents, my grandmother, and my godmother for their constant support (morally and financially) and encouragement to move forward through bad times.

Finally, I thank to my IFP School friends, Juliette, Nicolas, Charlotte; Aggie friends Linda, Nesrine, Fabrice, Raffaele, JC; and the Euro Department French section for their support and kindness.

I would like to add a special thanks to Claudia and Ted Granovsky for their help, support, and kindness in maintaining a familial life in a foreign country.

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CHAPTER I

INTRODUCTION

Carbonate rocks make up less than 10% of the rock record, yet they contain half of the world's oil and gas reserves, about 60% of which remain in place after primary recovery methods have been completed on established fields. Many of these fields are classified as "giant fields" and still contain large reserves of petroleum. To date, there has been limited success in finding reliable methods for evaluating reservoir quality in carbonates. Finding such a method, or methods, will significantly advance our ability to understand the relationships between rock properties and reservoir characteristics. It will also greatly improve our ability to conduct economically sound secondary and tertiary recovery projects and improve our ability to predict the spatial distribution of petrophysical rock types in the subsurface.

1.1. DEFINITION OF THE PROBLEM

Pores are connected by pore throats in reservoir rocks. Each pore size tends to be associated with a limited range of throat sizes. McCreesh, Ehrlich, and Crabtree (1991) showed "that different kinds of pores commonly form quasi-independent flow circuits, each with a characteristic throat size." Recent advances in methods to evaluate carbonate reservoir quality have focused on petrophysical measurements such as capillary pressures.

The thesis follows the style of American Association of Petroleum Geologists Bulletin.

One such method was developed during the 1970s by H. D. Winland of Amoco Oil Company (Kolodzie, 1980). Winland, who was interested in sealing potential, developed an empirical relationship between porosity, air permeability, and the pore aperture corresponding to a mercury non-wetting phase of 35% (R35) for a mixed suite of sandstones and carbonates. Winland ran multiple regression analyses for other values of mercury saturations–the points at which 30%, 40%, and 50% of pore–pore throat system was saturated with mercury. The best correlation between porosity and permeability (highest correlation coefficient, R) corresponded to the pore throat size at which 35% of the pore volume was filled with mercury. This 35th percentile approximated the modal class of pore throat size where the pore network becomes interconnected, forming a continuous fluid path through the sample. The data included 82 low-permeability samples (56 sandstones and 26 carbonates) corrected for gas slippage and 240 uncorrected samples with uncorrected permeabilities. The Winland equation was used and published by Kolodzie (1980):

$$\mathbf{Log\ R35 = 0.732 + 0.588\ (Log\ K_{air}) - 0.864\ (Log\ \Phi)}$$

where R35 is the pore aperture radius at which the non-wetting phase saturation is 35% of pore–pore throat volume, K_{air} is the uncorrected air permeability (millidarcies), and Φ is porosity (percent).

As an alternative to the Winland R35 criterion, E. D. Pittman (1992) developed the "apex method" based on capillary pressure measurements from 196 sandstone samples to find with greater accuracy the modal class of pore throat size. He took the apex of the hyperbola of the plot of mercury saturation–capillary pressure versus mercury saturation. He argued that a more reliable reservoir quality indicator is the point at which 36% non-wetting of saturation occurs – in other words, R36. Pittman's results are in line with those of Winland and are probably reliable criteria for defining reservoir quality in rocks that have exclusively interparticle porosity between relatively uniform particle sizes. This method does not work with low-permeability samples because capillary pressure values plot on a non-hyperbolic curve; consequently, they lack an apex.

A drawback to the Winland R35 criteria as a universal reservoir quality indicator is that the throats that connect pores in carbonate rocks may vary in size from less than 1 μm to several microns, while the corresponding pore sizes can vary so widely that there is no clear correspondence between storage capacity (porosity) and flow capacity (permeability). The Winland equation is based on the initial assumption that there is a linear relationship between porosity, permeability, and R35. This assumption is obvious in a simple network such as that in interparticle porosity (sandstone). Applying the same method in heterogeneous sandstone, Pittman (1992) found reproducible results at 25% mercury saturation, Spearing, Allen, and McAylay's (2001) results indicated saturation values below 35%, Porras et al. (2001) found reproducible results at 45% saturation, and Rezaee, Jafari, and Kazemzadeh (2006) suggested that the pore throat size at which mercury saturation is 50% gave the most reliable results on carbonate pore networks. All of these examples indicate that no single modal class of pore throat size predicts values of porosity and permeability.

Another drawback to using the R35 method on some carbonate rocks is that pore types are not classified according to size, shape, or origin. In many carbonates, it is the pore geometry that provides clues to their origin, which, in turn, provides information about the spatial distribution in reservoirs and about predictability of pore sizes. For example, pores and pore throats in mud-supported rocks are much smaller than pores in grain-supported rocks, as the Lucia (1995) geological rock "typing" method indicates. Vuggy pores may vary in size from a few microns to many centimeters in length or width; therefore, a quality evaluation that includes porosity classification should be more powerful than one that does not.

Lucia (1983, 1995) used a more geological approach in his classification of carbonate porosity. He divided pore types into two categories: interparticle and vuggy porosity, with vuggy porosity further divided into separate vug pores and touching vug pores, and interparticle porosity further subdivided into grain-dominated and mud-dominated categories. In order to define reservoir quality, Lucia identified three geologically based, petrophysical rock classes based on rock fabrics. The classes correspond in general to porosity and permeability classes, with class 1 consisting of grainstone fabrics, class 2 consisting of grain-dominated, packstone fabric, and class 3 consisting of mud-dominated fabric. Lucia (1999) compared these rock-fabric fields with cross plots of porosity, permeability, and R35 pore throat size based on Pittman's (1992) work. Lucia demonstrated that non-touching vug porosity cannot be reliably evaluated for reservoir quality using the Winland R35 criterion because the mixture of separate vugs and variably sized "matrix" pores fills with mercury at different rates and different pressures; therefore, the point at which 35% of the pore volume is filled with mercury may not be a true indicator of the best combination of porosity and permeability.

A new genetic porosity classification for carbonate reservoirs was developed by Ahr (Ahr and Hammel, 1999; Ahr, 2005). It revolves around the origin of pore types, including depositional, diagenetic, and fracture varieties (Figure 1).

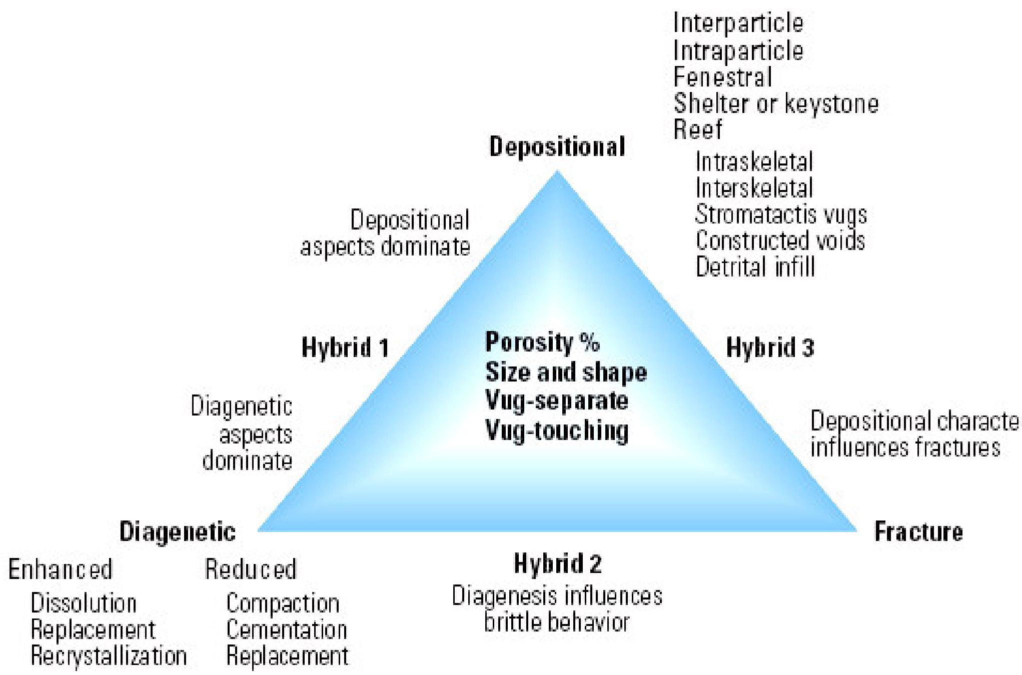

Figure 1. Ahr classification (2005) for carbonate.

This study evaluates an alternative to the R35 criterion by first applying the Pittman and Hartmann criteria to capillary pressure data from Smackover and Permian reservoirs. It then presents an alternative method based on genetic pore type to provide more reliable results.

1.2. OBJECTIVES OF THE STUDY

1. Collect and inventory MICP data and porosity–permeability data from core analysis from four different locations:
    - Happy Field, Permian Clearfork Formation, Garza County, Texas
    - Vocation/Appleton Fields, Upper Jurassic (Oxfordian) Smackover Formation**,** Monroe County, Alabama
    - Womack Hill Field, Upper Jurassic Smackover Formation, Clarke and Choctaw Counties, Alabama

2. Define the R35 method.

3. Establish limitations of the R35 method, citing examples from the literature.

4. Apply the R35 method to the collected data and interpret the results.

5. Compare R35 values from collected MICP values with those predicted by the Winland R35 equation.

6. Find the modal pore throat size class in the data sets and compare the results of R35 evaluation criteria with Pittman's apex criteria.

7. Develop an alternative method, based on genetic porosity classification developed by Ahr, to determine reservoir quality.

1.3. MATERIALS FOR THE STUDY

Thirty-three samples were subjected to mercury injection capillary pressure measurements. The samples represent 1) Vocation/ Appleton Fields, Monroe County, Alabama (Jurassic, Smackover Formation) (Morgan, 2003), 2) Womack Hill Field, Clark and Choctaw Counties, Alabama (Jurassic, Smackover Formation) (Hopkins, 2002), and 3) Happy Spraberry Field, Garza County, West Texas (Permian, Clearfork Formation) (Hammel, 1996). These data were taken from a thesis by Adams (2005). Table 1 presents a summary of materials used in this project.

Table 1. Summary of materials available for this project

Data Type	Happy Field	Vocation/Appleton Fields	Womack Hill Field
Geographic Location	West Texas	Alabama Gulf Coast	Alabama Gulf Coast
Formation Name	Clearfork	Smackover	Smackover
Formation Age	Permian	Upper Jurassic	Upper Jurassic
Number of Complete MICP Reports	3	19	11
Number of Wells Represented	2	6	2

Adams (2005) also identified pore geometry and genetic pore category in 33 thin sections. This data comprise the essential element of the alternative method for quality evaluation presented later in this study.

CHAPTER II

GEOLOGICAL SETTING

Data available for this study come from two different formations: Smackover Formation (Vocation/Appleton Fields and Womack Hill Field) and Clearfork Formation (Happy Field).

2.1. SMACKOVER FORMATION

The Smackover Formation was deposited on a carbonate ramp (Ahr, 1973). It has been identified as Oxfordian in age based upon the occurrence of fossil ammonites. Thirty of 33 samples used in the set of data come from Smackover Formation. They are from three fields: Womack Hill Field (Figure 2), Choctaw and Clark Counties, and Vocation and Appleton Fields (Figure 2), Monroe County.

2.1.1. Types of facies in Alabama fields

2.1.1.1. Womack Hill Field

The Smackover Formation includes lower, middle, and upper units in Womack Hill field. The lower unit of the Smackover is typically composed of peloidal packstone and wackestone. The middle unit includes laminated lime mudstone and fossiliferous wackestone and lime mudstone. Porosity is developed in the upper part of the middle Smackover in the south-central part of the field (Mancini et al., 2004).

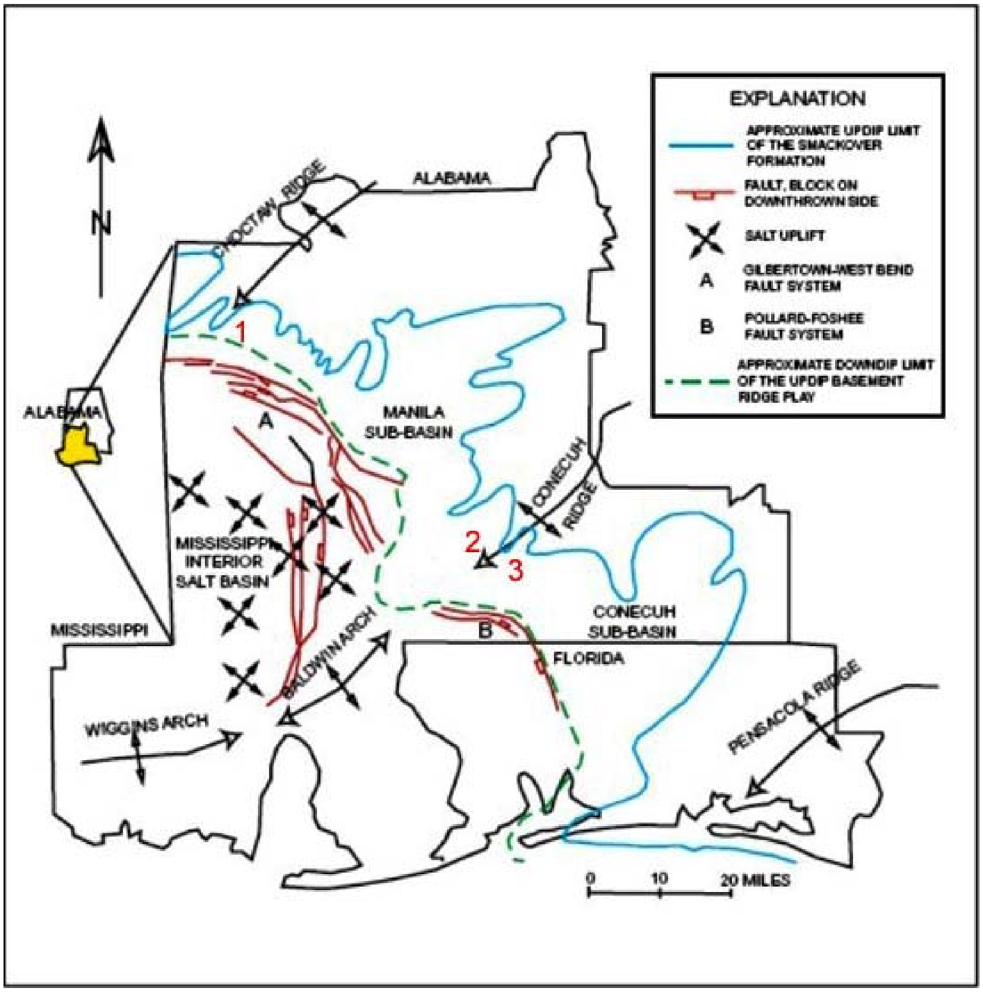

Figure 2. Location map of major regional structures and fields: 1. Womack Hill Field, 2. Vocation Field, 3. Appleton Field (modified from Llinas, 2002b).

2.1.1.2. Vocation and Appleton Fields

According to Benson et al. (1997), "The reservoir grade porosity in the Smackover at Appleton Field occurs in microbial (algal) boundstones and bindstones in the reef interval in the middle Smackover and in mixed oolitic, oncoidal, and peloidal grainstones, and packstones in the upper Smackover. Porosity in the boundstones and bindstones is a mixture of primary shelter porosity overprinted by secondary intercrystalline porosity produced by dolomitization, which is pervasive throughout much of the field. Porosity in the grainstones and packstones is a mixture of primary interparticle and secondary moldic porosity again overprinted by secondary dolomite intercrystalline porosity."

2.1.2. Pore characteristics

Although the primary control in reservoir architecture in Smackover carbonates is the depositional fabric, diagenesis is a significant factor in modifying reservoir quality (Benson, 1985). Multiple events of dolomitization and dissolution probably had the greatest influence on reservoir quality. Although dolomitization created only minor amounts of intercrystalline porosity, it significantly enhanced or reduced permeability; it also stabilized the lithology that reduced the potential for later porosity loss because of compaction (Benson, 1985).

Dissolution diagenesis enlarged the original, depositional (interparticle) and early secondary (moldic and intercrystalline) pores (McKee, 1990). Although dissolution did not create large amounts of new porosity, it did expand existing pore throats and enhance permeability (Benson, 1985). Porosity in the Smackover Formation is related to depositional lithology and altered by diagenesis.

Four types of porosity with the same characteristics are observed: primary interparticle, moldic, vuggy, and dolomitic intercrystalline.

Primary interparticle pores appear as depositional voids between allochems. Interparticle porosity is restricted to the oolitic and peloidal grainstone lithologies of the upper Smackover. Primary porosity, reduced by compaction and cementation, possesses small-to-moderate amounts of marine or meteoric phreatic cement, which reduces the effects of compaction. Lithologies, which lack early cements due to rapid burial and lack of exposure to meteoric vadose fluids, are characterized by extensive physical compaction, and much of the primary porosity is lost. At the same time, lithologies that spent considerable time in the meteoric phreatic zone have had much of the primary porosity occluded by precipitation of granular and blocky cements (Benson, 1986).

Moldic porosity is common in the Smackover Formation. Moldic porosity is the product of dissolution of aragonitic or magnesium calcitic ooids. The nature of the pores indicates the dissolution occurred before the lithology was mineralogically stabilized; therefore, it suggests that the dissolution occurred in the meteoric vadose zone. The size of the pores is usually a function of the size of the original allochem. Unless the original packing density is high, most moldic pores are poorly interconnected. Lithologies that possess only moldic porosity typically have very low permeability and poor reservoir quality. Permeability is enhanced in grainstone lithologies that have been dolomitized and possess intercrystalline porosity in addition to the moldic (Benson, 1986).

In these fields, *vuggy pores* are defined as dissolution pores that are larger than their surrounding framework particles. This dissolution, occurring after depositional particulates of unstable mineralogy (Benson, 1986), has inverted to stable, low-magnesium calcite. Thus, it is a late-stage process. Vuggy formation is primarily a burial process. Vugs in the Smackover commonly form through solution enlargement of primary interparticle, moldic, or dolomitic intercrystalline pores (Benson, 1986).

Intercrystalline porosity is the product of the volume change associated with the replacement of calcite by dolomite. The porosity occurs in the form of fine pores between the dolomite crystals in extensively dolomitized lithologies. Intercrystalline porosity is characterized by intercrystalline pores of relatively uniform size, which are evenly distributed throughout the lithology. The morphology of the pores is determined by the nature of the dolomite (Benson, 1986).

2.2. PERMIAN BASIN – WEST TEXAS

The Permian Basin of West Texas and Southeastern New Mexico is an intracratonic foreland basin. The focus of this study is the formation of the Midland Basin, located between the central basin platform and the eastern shelf margin of the Permian Basin proper (Figure 3).

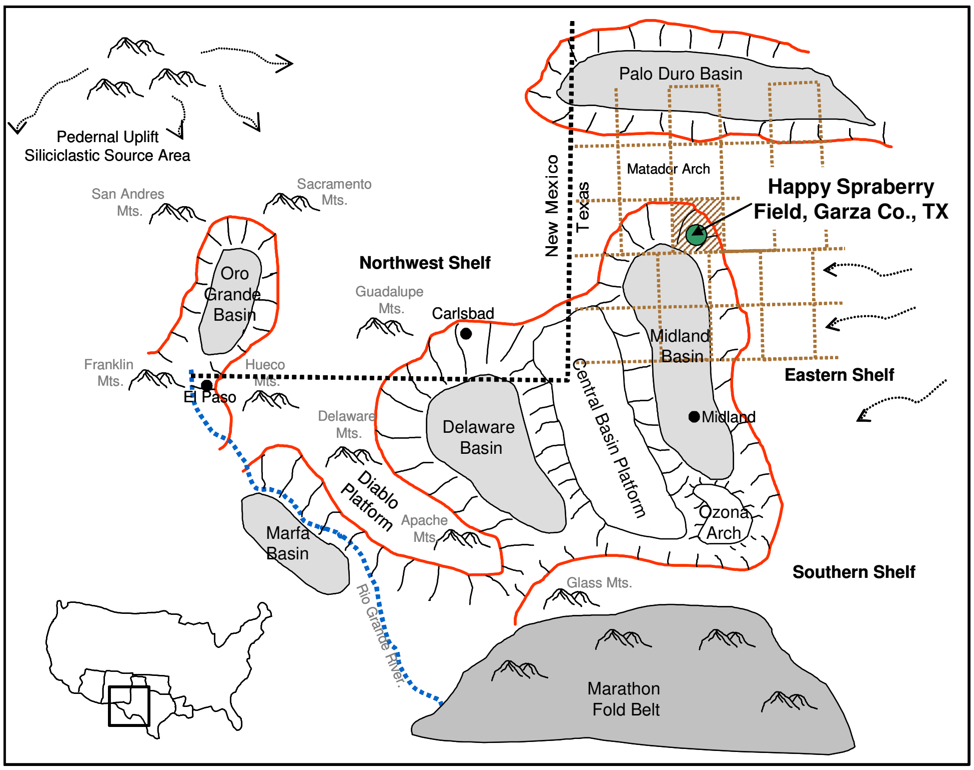

Figure 3. Composite map showing regional paleogeography of the Permian Basin including modern physiographic features (modified from Atchley, Kozar, and Yose, 1999; Handford, 1981). Map shows location of Happy Spraberry Field in Garza County, Texas.

Happy Field is located in Garza County, Texas. The field name should not be confused with the deep water turbidites of the Spraberry Formation, which occurs in the central deep portion of the Midland Basin (Handford, 1981).

2.2.1. Types of facies in Happy Field

Happy Field is formed from shallow water carbonates that were deposited near the downdip margin of the Eastern Shelf. The limestone reservoir consists of three lithofacies: skeletal rudstone/packstone, oolitic-peloidal grainstone, and oolitic-peloidal packstone. Depositional environments vary from open marine skeletal banks to subtidal grainstone shoals (Hammel, 1996). Four depositional pore types were identified: intergranular, interparticle, shelter, and intraskeletal (Ahr and Hammel, 1999). Seven diagenetic pore types (Hammel, 1996) were identified: grain-moldic, incomplete grain-moldic, vuggy, solution-enhanced intergranular, solution-enhanced intercrystalline, cement-reduced intercrystalline, and solution-enhanced interparticle (Ahr and Hammel, 1999).

2.2.2. Pore characteristics of Happy Field

The only pore type examined in this study is moldic porosity. It consists of isolated molds in highly cemented oolitic skeletal grainstones where leaching affected only metastable grains (Layman and Ahr, 2004, 2005).

CHAPTER III

REVIEW OF THE R35 METHOD

Petrophysical measurements such as capillary pressure are commonly used to evaluate carbonate reservoir quality. The pore throat size can be directly calculated from the capillary pressure curve, so the challenge is to define the non-wetting phase saturation that defines the best reservoir quality.

3.1. CAPILLARY PRESSURE: A REVIEW

Capillary pressure is the difference in pressure across the interface between two immiscible fluids and is defined as

$$P_c = P_{\text{non-wetting phase}} - P_{\text{wetting phase}}$$

In oil-water systems, water is typically the wetting phase; for gas-oil systems, oil is the wetting phase.

Mercury, the non-wetting phase in this measurement, is injected under pressure into a clean ”perm plug.” The non-wetting phase saturation is determined by the volume of mercury in the plug at various pressures. To build the injection, or drainage, curve (Figure 4, curve 1), mercury is injected until a minimum unsaturated pore volume is reached. This volume corresponds more or less to irreducible water saturation in reservoirs. To generate an imbibition curve, pressure is relaxed until it reaches ambient conditions. The withdrawal, or imbibitions, curve (Figure 4, curve 2) represents the amount of mercury that remains in the plug (residual saturation) and the amount that is withdrawn.

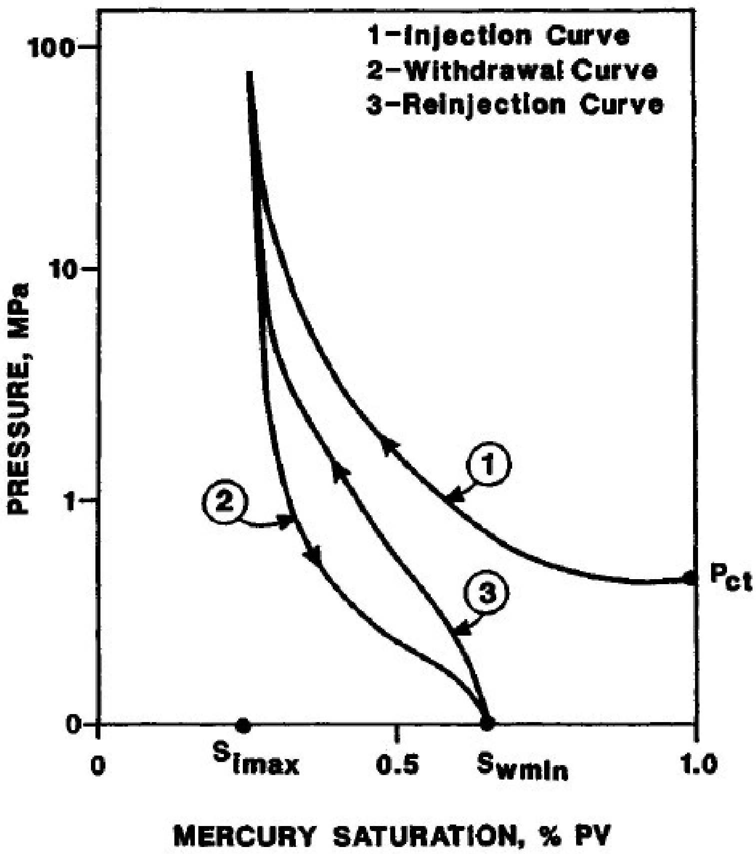

Figure 4. Mercury–gas capillary pressure curves showing the initial injection curve with its threshold pressure and the hysteresis loop (Tiab and Donaldson, 2004).

3.2. PORE THROAT RADIUS

Pore throat radii in MICP measurements can be calculated using the following equation:

$$P_c = 2\gamma \cos\theta / r$$

The Washburn equation states that this pressure difference is proportional to the surface tension, γ, and inversely proportional to the effective radius, r, of the interface; it also depends on the wetting angle, θ, of the liquid on the surface of the capillary.

3.2.1. Review of different methods to qualify a reservoir using capillary pressure curve to define the pore throat size

Some authors (e.g., Pittman 1992) recognized the importance of capillary pressure as a means to estimate permeability when using the Winland equation or similar equations in which porosity, permeability, and capillary pressure are involved. The pore throat size can indicate reservoir quality. The challenge is to identify at which saturation of non-wetting phase corresponds to the pore throat radius.

Capillary pressure curves indicate pore throat size, which is related to permeability. Some authors (Winland published by Kolodzie, 1980; Swanson, 1981; Katz and Thompson, 1986) used the “knees,” or the flat portion, of the capillary pressure curves (Figure 5) to establish a mathematical relationship between rock dimension/parameters (pore throat size) and permeability. Because the pore throat radius defined is located on the flat portion, the capillary pressures are almost equal. As a consequence, the pore throat radii, for all corresponding water saturations, are nearly equal.

Others prefer to use the oblique/vertical section on the capillary pressure–water saturation curve (Timur, 1968; Granberry and Keelan, 1977; Purcell, 1949), as depicted in Figure 5. This means that the authors considered the most reliable point at which to measure pore throat size to be the point at irreducible water saturation (S_{wi}). The R35 (object of this study), proposed by Winland (1978), is not consistent with irreducible conditions because the pore throat radius is calculated at 35% of non-wetting phase (Haro, 2004).

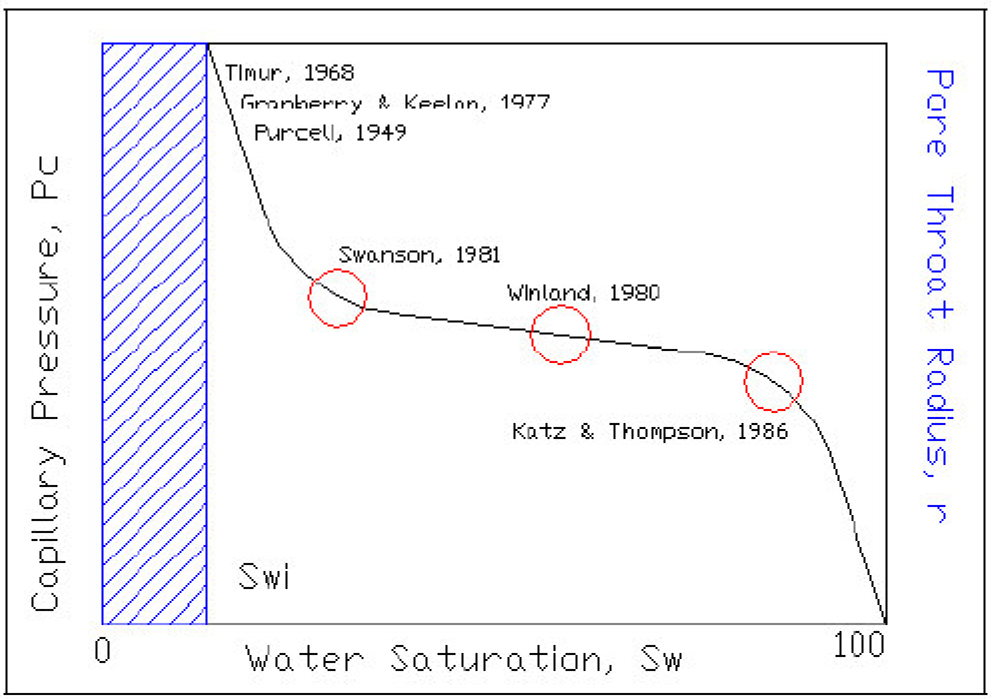

Figure 5. Capillary pressure curve pore throat radius (Nelson, 1994; Haro, 2004).

The more common method used by the geosciences community to assess reservoir quality on the basis of pore throat size is the Winland (R35) method described by Kolodzie (1980). This method links porosity, permeability, and pore throat radius at 35% non-wetting phase saturation.

3.2.2. Winland R35 method

H. D. Winland of Amoco used mercury injection–capillary pressure curves to develop an empirical relationship between porosity, permeability, and pore throat radius on reservoir rocks from Spindle Field, Colorado. Winland tested 312 different water-wet samples to evaluate sealing potential. The data included 240 uncorrected samples and 82 low permeability samples (56 sandstones and 26 carbonates) corrected for gas slippage. Winland's experiments revealed that the effective pore system that dominates flow through rocks in his set of samples corresponded to a mercury saturation of 35%. No satisfactory explanation has been presented to explain why this relationship is 35%, but it corresponds to a mean pore throat size of 0.5 μm in the Winland samples. The variation of the pore throat size below this limit indicates the boundary of the trap on the updip side of Spindle Field. This limit size is used as a cut-off to determine the net pay intervals (Kolodzie, 1980). Hartmann and Beaumont (1999) described the R35 as "a pore throat radius (called pore aperture at 35% of non-wetting phase) equal to or less than the pore throats entered when a rock is saturated 35% with non-wetting phase fluid." After 35% of the pore system fills with a non-wetting phase fluid (like mercury), the remaining pore system does not contribute to flow. On the contrary, it contributes to storage (Hartmann and Beaumont, 1999).

Pittman (1989) studied some of the same rocks that Winland used and he found, that the net feet of sandstone having an R35 lower than 0.5 µm was useful to determine the point at which hydrocarbon trapping would occur. Good productive wells in the field have averages of 39 ft of net sandstone with an R35 greater than 0.5 µm, whereas updip dry holes have zero net sandstone thickness with R35 values greater than 0.5 µm (Pittman, 1992).

The problem is that method works on sandstone reservoir but not on complex carbonate network. Using empirical equation with coefficient adjust for the field they were studied, Winland (Kolodzie, 1980) and Pittman (1992) proposed, respectively, R35 and R25 as the best permeability estimators for sandstone.

A possible explanation from Rezaee et al. (2006) to explain the difference of non-wetting saturation corresponding to the pore throat size to determine reservoir quality is the complexity of the pore network of carbonates compared for sandstone. In sandstones, porosity is intergranular (homogeneous porosity), whereas for carbonates, porosity types (heterogeneous porosity) vary widely (Choquette and Pray, 1970; Ahr, 2005).

3.2.3. Analysis of the R35 method

The Winland equation was derived from capillary pressure data to obtain real pore throat geometry to identify pore throat radius (R35) at 35% non-wetting fluid saturation. While R35 mathematically satisfies the necessary conditions to identify a given pore throat size distribution, it is not sufficient to define a unique distribution. It could correspond to various distributions, passing through the same point with different permeability values. Further, bimodal distributions are not taken into account. The Winland model assumes a series of straight, smooth, circular, non-communicating capillary tubes/pore throats because of limitations of how capillary pressure is modeled. It does not, therefore, take into consideration tortuosity, wettability, or branchiness of the pore system–nor is there a shape factor, *sensu* (Thomeer, 1960), to correct for non-circular capillary tubes/pore throats. Pore throat radius is obtained in the transition zone, and taking into consideration that the wetting/non-wetting fluid is difficult to determine in the transition zone, there is no clear physical justification for a specific percentile of non-wetting fluid saturation value (Haro, 2004).

3.2.4. Other methods to determine reservoir quality

Three methods are reviewed in this thesis–the Pittman (1992) method, the regression analysis method of Winland and Pittman, and the Lucia geological rock method of rock typing.

3.2.4.1. The Pittman method

Pittman (1992) tested the Winland method on samples corrected for gas slippage from clastic reservoirs (sandstone) that range in age from Ordovician to Tertiary. These sandstone formations vary in composition, texture, and structure. Pittman improved the Winland method by developing a technique to more accurately define modal pore aperture.

His apex technique is based on the following analysis of the mercury injection curve: "Entry pressure, displacement pressure, and threshold pressure are terms referring to the initial part of the mercury injection curve. The entry pressure on a mercury injection-capillary pressure plot is the point on the curve where the mercury first enters the pores of the rock. This point is indicative of the largest pore aperture size (Robinson, 1966). This parameter often is vague and difficult to determine because the sample size and surface irregularities of the rock relative to pore geometry create a boundary condition that affects the low-mercury saturation part of the curve."

Schowalter (1979) recognized this problem and pointed out that it is important to determine the pressure required to form a connecting filament of non-wetting fluid through the largest connected pore apertures of the rock. He also defined the term *displacement pressure* as the pressure at 10% mercury saturation for use in evaluation of hydrocarbon entrapment. Katz and Thompson (1986, 1987) defined *threshold pressure* as the pressure at which mercury forms a connected pathway across the sample. They indicated that the measured threshold pressure corresponded graphically to the inflection point on the mercury injection plot. However, this method was inaccurate.

Figure 6 shows a mercury injection–capillary pressure curve.

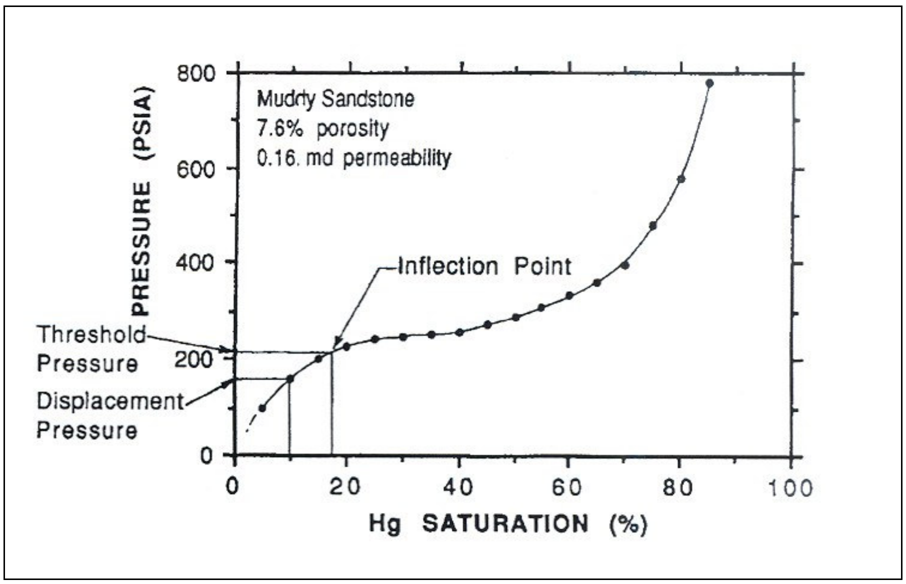

Figure 6. The mercury injection–capillary pressure plot showing the inflection point and the threshold pressure (Pittman, 1992).

The threshold pressure, as defined graphically by Katz and Thompson (1987), corresponds to the inflection point at which the curve becomes convex upward. Swanson (1977) determined this inflection point on a mercury injection curve as corresponding to the apex of a hyperbola on a log-log plot. In Figure 7, the 45-degree line is tangent to the hyperbola at the apex (Pittman, 1992).

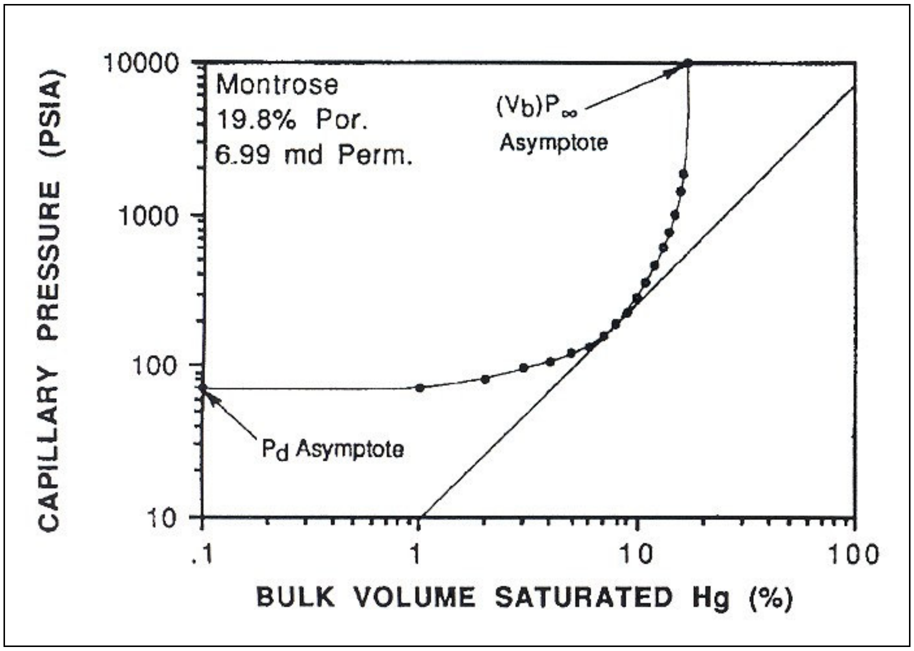

Figure 7. A log-log hyperbolic plot of mercury injection showing the apex of the hyperbola (Pittman, 1992).

Pittman generated plots of mercury saturation versus mercury saturation–capillary pressure to more accurately define the inflection point, as illustrated in Figure 8. For some samples, the inflection point is vague and difficult to determine. As a result, a plot of mercury saturation–capillary pressure versus mercury saturation was identified by Pittman (1992). However, he did not find any apices for low-permeability samples because the curve is non-hyperbolic, even though modal classes of pore throat sizes may exist below the resolving power of the method.

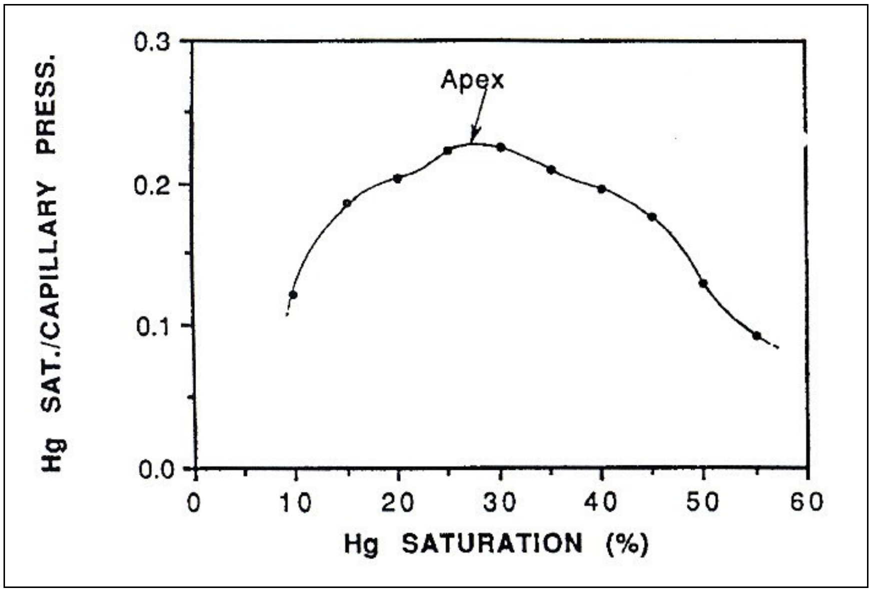

Figure 8. A plot of mercury saturation–capillary pressure versus mercury saturation as a means of determining the apex of hyperbola (Pittman, 1992).

With this more accurate method, Pittman discovered that the effective pore system that dominates flow through this type of rock corresponds to a pore throat size at which the mercury saturation is 36%. This is very similar to the Winland R35 results. As an explanation, Pittman (1992) wrote, "Winland found the best correlation to be for R35 because that is where the average modal pore aperture occurs and where the pore network is developed to the point of serving as an effective pore system that dominates flow in the sense described by Swanson (1981)."

Spearing et al. (2001) used the Winland method as a tool to define a net pay cut-off in order to exclude very low porosity-permeability. He used the accurate Pittman technique to find the R (inflection). In all cases, the mercury saturation corresponding to R (inflection) did not equal 35% and was usually lower than 35%. It can be noted that the points of inflection were found graphically for all low-permeability samples in this case.

It is well known that there is a relationship between pore throat and pore size in sandstone reservoirs (McCreesh et al., 1991). That relationship is reliable in a homogeneous case such as interparticle porosity with a minimum of diagenesis. A problem arises when the network becomes increasingly complex, as occurs in carbonate rocks. The throats that connect pores vary significantly in size from less than 1 μm to several microns; therefore, the relationship between porosity (storage capacity), permeability (flow capacity), and pore throat radius is not always obvious.

3.2.4.2. Winland's Application of Regression Analysis Techniques

Winland developed the following empirical relationship between porosity, air permeability, and pore throat size corresponding to a mercury saturation of 35% using sandstone and carbonate samples:

$$\text{Log } R35 = 0.732 + 0.588\,(\text{Log } K_{air}) - 0.864\,(\text{Log } \Phi)$$

where K is the uncorrected air permeability (in millidarcies), Φ is the porosity (in percent), and R35 (expressed in microns) is the pore throat radius at 35% mercury saturation from a mercury injection capillary pressure test.

Pittman (1992) used Winland's multiple regression analysis approach to develop an empirical equation for calculating the pore throat that corresponds to the 35th percentile was extended to a spread of mercury saturation percentiles (Table 2).

Table 2. Empirical equation for determining pore aperture radii corresponding to various mercury saturation percentiles (Pittman, 1992).

Equations	Correlation Coefficient
$\text{Log } r_{10} = 0.459 + 0.500 \text{ Log K} - 0.385 \text{ Log } \varnothing^*$	0.901
$\text{Log } r_{15} = 0.333 + 0.509 \text{ Log K} - 0.344 \text{ Log } \varnothing^*$	0.919
$\text{Log } r_{20} = 0.218 + 0.519 \text{ Log K} - 0.303 \text{ Log } \varnothing^*$	0.926
$\text{Log } r_{25} = 0.204 + 0.531 \text{ Log K} - 0.350 \text{ Log } \varnothing^*$	0.926
$\text{Log } r_{30} = 0.215 + 0.547 \text{ Log K} - 0.420 \text{ Log } \varnothing^*$	0.923
$\text{Log } r_{35} = 0.255 + 0.565 \text{ Log K} - 0.523 \text{ Log } \varnothing^*$	0.918
$\text{Log } r_{40} = 0.360 + 0.582 \text{ Log K} - 0.680 \text{ Log } \varnothing$	0.918
$\text{Log } r_{45} = 0.609 + 0.608 \text{ Log K} - 0.974 \text{ Log } \varnothing$	0.913
$\text{Log } r_{50} = 0.778 + 0.626 \text{ Log K} - 1.205 \text{ Log } \varnothing$	0.908
$\text{Log } r_{55} = 0.948 + 0.632 \text{ Log K} -1.426 \text{ Log } \varnothing$	0.900
$\text{Log } r_{60} = 1.096 + 0.648 \text{ Log K} - 1.666 \text{ Log } \varnothing$	0.893
$\text{Log } r_{65} = 1.372 + 0.643 \text{ Log K} - 1.979 \text{ Log } \varnothing$	0.876
$\text{Log } r_{70} = 1.664 + 0.627 \text{ Log K} - 2.314 \text{ Log } \varnothing$	0.862
$\text{Log } r_{75} = 1.880 + 0.609 \text{ Log K} - 2.626 \text{ Log } \varnothing$	0.820

*Ø is statistically insignificant. A regression excluding Ø yields essentially the same result. k = permeability (md) and Ø = porosity (%).

The empirical equation for pore aperture corresponding to mercury saturation percentiles from 10% to 55% had correlation coefficient values above 0.900 with the highest correlation coefficients occurring at mercury saturation values corresponding to points between R25 and R20.

Porras (2001) used plots (Figure 9) of pore throat radius from capillary pressure data versus pore throat radius obtained from Pittman's equation to define the appropriate equation to estimate pore throat size in a complex system in sandstones.

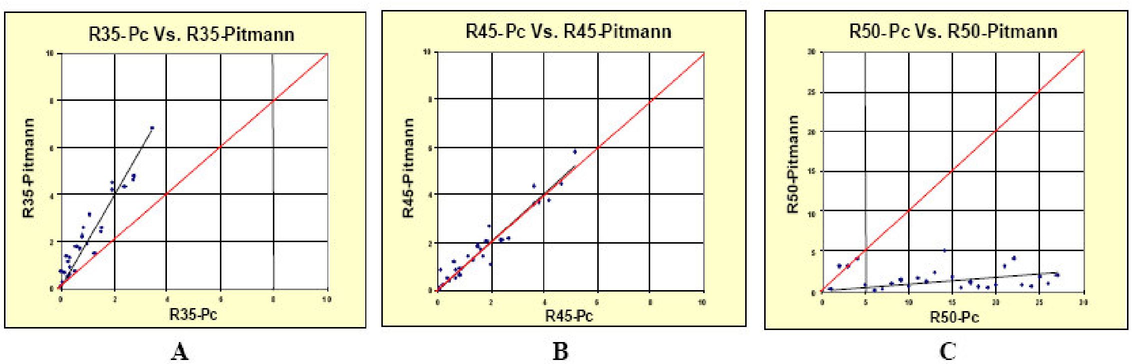

Figure 9. Pore throat radii estimated from mercury injection–capillary pressure data versus calculated pore throat radii showing the best correlation with Pittman's R45 (Porras, 2001).

The R45 equation perfectly matches with core capillary pressure. It is also differs from Winland's R35 results.

Rezaee et al. (2006), using statistical software, developed an empirical equation for calculating permeability from porosity values and pore throat sizes. They found the best correlation coefficient for carbonates with complex networks is at R50. Then they used the ANN (Artificial Neutral Network), a biologically inspired computing scheme that can solve complex problems. At each stage of the process, pore throat radius in a spread of mercury saturation percentiles and the logarithm of porosity were fed as input and the logarithm of permeability as output. The best fit using this synthetic method is also at the 50th percentile.

3.2.4.3. The R35 criterion and the Lucia rock type classification

The Winland R35 transform performs best in intergranular, interparticle, or intercrystalline pore systems.

The Lucia carbonate porosity classification (1995) distinguishes between interparticle porosity and vuggy porosity. Lucia (1983, 1995) further divided vuggy porosity into two different categories: touching vugs and separate vugs (Figure 10). Vugs are pores either within particles or in the rock matrix and are significantly larger than any constituent particles. Separate vugs are interconnected only through the matrix porosity, while touching vugs are connected through the vug system itself. Some fracture porosity behaves in a similar petrophysical sense to touching vug pores, because pure fracture permeability is connected through the fracture system rather than through the matrix pores. Separate vug pores (vug-to-matrix-to-vug connection) (Figure 10) and touching vug pore systems are defined as pore space that is significantly larger than the particle size and that forms an interconnected pore system of significant extent.

Three classes were defined by Lucia (1995). They correspond in general to particle size classes. Class 1 is based in larger particle sizes such as those in grainstone fabrics, class 2 is grain-dominated, packstone fabric, and class 3 is mud-dominated fabric. Lucia (1999) compared these rock-fabric fields with cross plots of porosity, permeability, and R35 pore throat size based on Pittman's (1992) work.

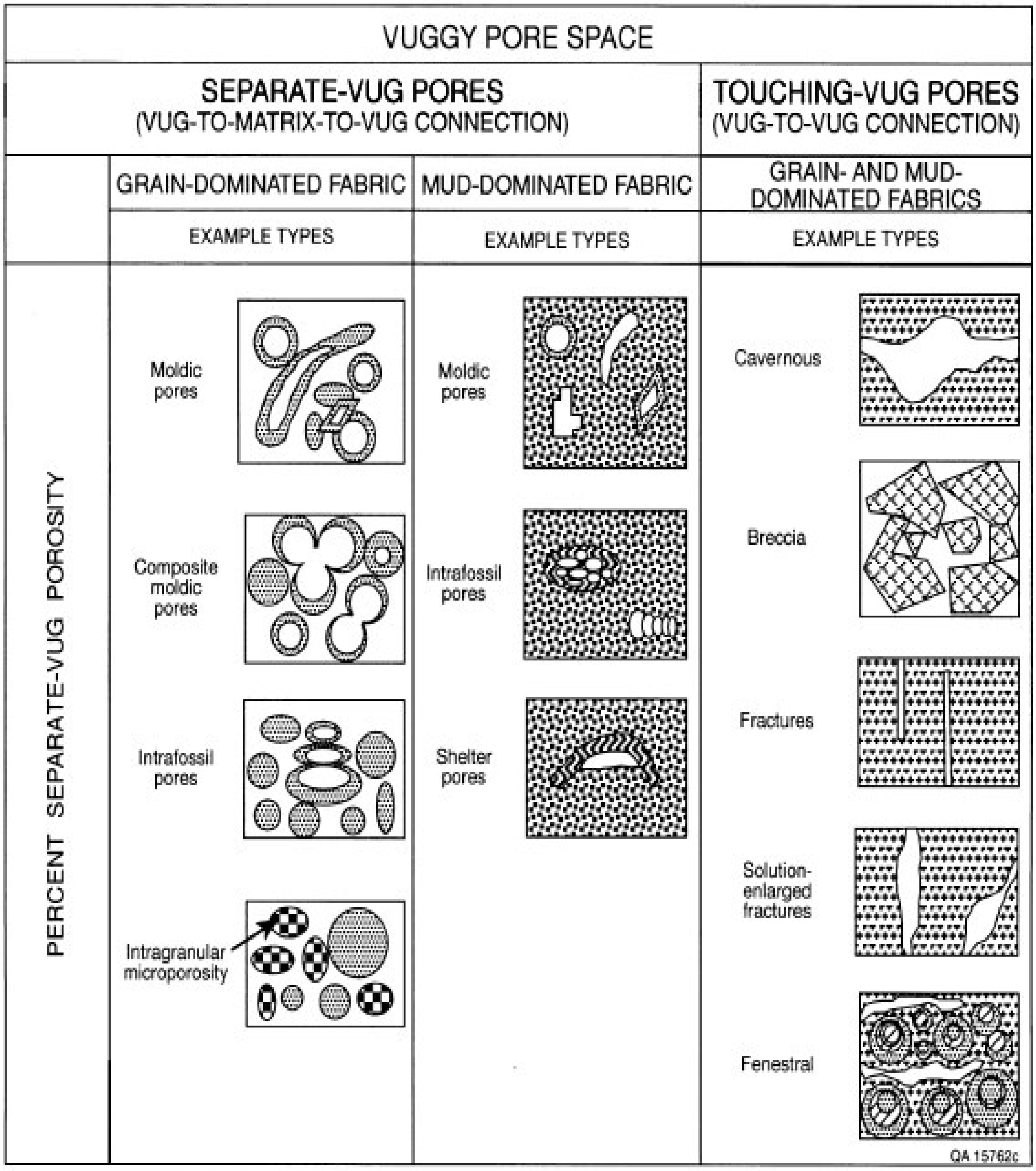

Figure 10. Geological and petrophysical classification of vuggy pore space based on vug interconnection (Lucia, 1995).

Lucia identified two categories: 1) vuggy porosity is connected through the matrix pore system and 2) vugs are connected through the vug system itself. There is no distinction between grain-supported or mud-supported rocks. In his 1995 paper, Lucia demonstrated that connected vugs do not fit the R35 transform when the vug porosity is only a portion of the total porosity. He named this the bimodal system, which is a combination of intergranular porosity and vuggy porosity. Flow through cracks and connected vugs compute an R35 greater than that for the matrix. For fracture porosity, the R35 value is greater than expected (Aguilera, 2004). In order to solve the problem related to the bimodal porosity, Lucia isolated the pore throat aperture of the interparticle porosity and conducted a complete analysis pore throat aperture on the matrix. This method does not work well if the vugs are well extended spatially, as is usually the case with fracture.

The second category of vuggy porosity is non-touching vugs. When separate vugs occur in addition to matrix porosity, the R35 is still an approximate indicator of flow, but because the presence of vugs alters pore and pore throat geometry, the R35 overestimates porosity and permeability in altered rocks. Separate vugs usually do not increase flow but rather increase pore volume. The increased pore volume computes an R35 that is slightly below the matrix value. If most of the total porosity consisted of separated vugs, then the R35 might be slightly pessimistic (lower value) and matrix flow slightly better than the R35 indicates.

3.3. ALTERNATIVE METHOD

The challenge in the early 21st century is to understand carbonate reservoir in order to better develop oil fields. To achieve this objective, many tried to develop a carbonate pore and rock classification and use it as a tool to qualify a reservoir.

3.3.1. Review of carbonate classifications by rock type and by type of pore

There are two types of carbonate classification: by rock type and pore type.

3.3.1.1. Carbonate classification by rock type

Archie (1952) made the first tentative step in relating rock fabrics to petrographical rock properties in carbonate reservoirs. Archie focused on estimating porosity and permeability, using capillary pressure.

The Dunham (1962) classification (Figure 11) is mostly used by oil companies. It is focused on depositional texture and composition according to the texture and grain size of the rocks. It gives only an idea of the genetic significance of the porosity.

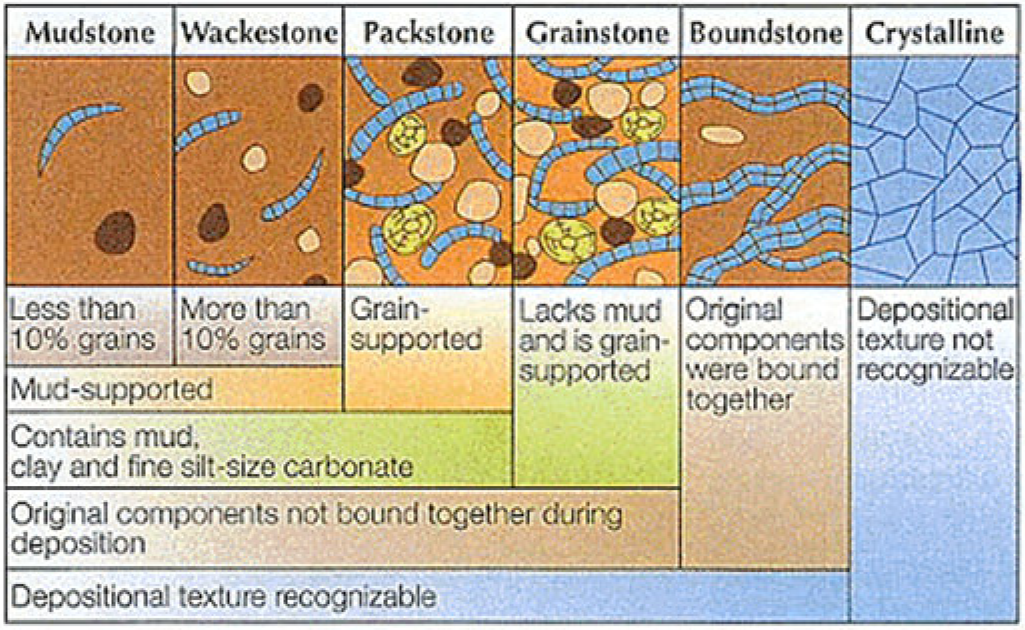

Figure 11. Dunham classification (modified from Dunham, 1962; www.glossary.oilfield.slb.com).

The Dunham classification-is similar to the Folk classification (1959). The Folk scheme details the relative proportion of allochems in the rock and the type of matrix or absence of matrix. Suffixes are used to describe the matrix, and prefixes are used to describe the main (non-matrix) component.

3.3.1.2. Carbonate pore classifications

Choquette and Pray (1970) introduced the concept of fabric selective porosity (Figure 12). *Fabric selective* is a term that refers to the dependent relationship between porosity and rock fabric. A fabric element is related to various types of primary sedimentary particles and secondary particles formed through diagenesis.

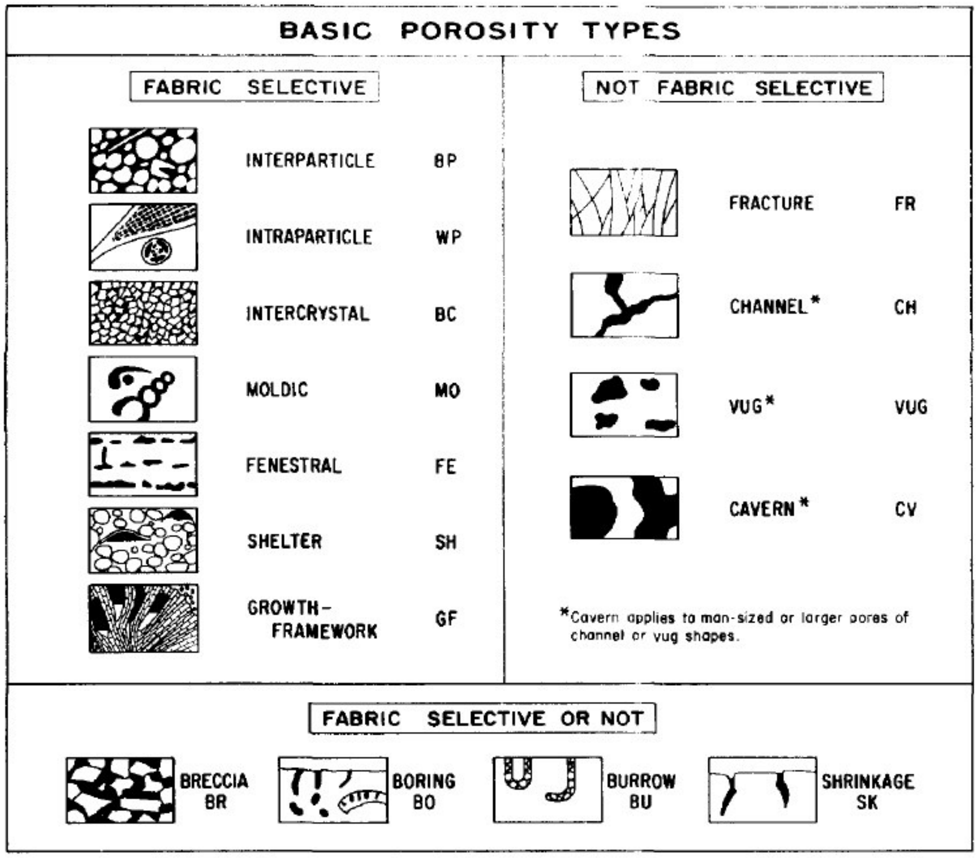

Figure 12. Choquette and Pray classification (Choquette and Pray, 1970).

Lucia's (1983) porosity classification, described earlier in this chapter (see Figure 10), based on particle sizes and different types of vuggy porosity is commonly used**.**

3.3.2. The Ahr genetic classification of carbonate porosity

The problem with the classifications described previously is that they do not consider the geological origin of porosity.

Ahr (2005) developed a new classification (Figure 13) based on the origin of the porosity where intergranular porosity in any detrital rock can be included. The end-members of the triangular classification are the origin of porosity: depositional, diagenetic, or fracture (Ahr, 2005). Those processes represent the cause, whereas genetic pore types represent the effects.

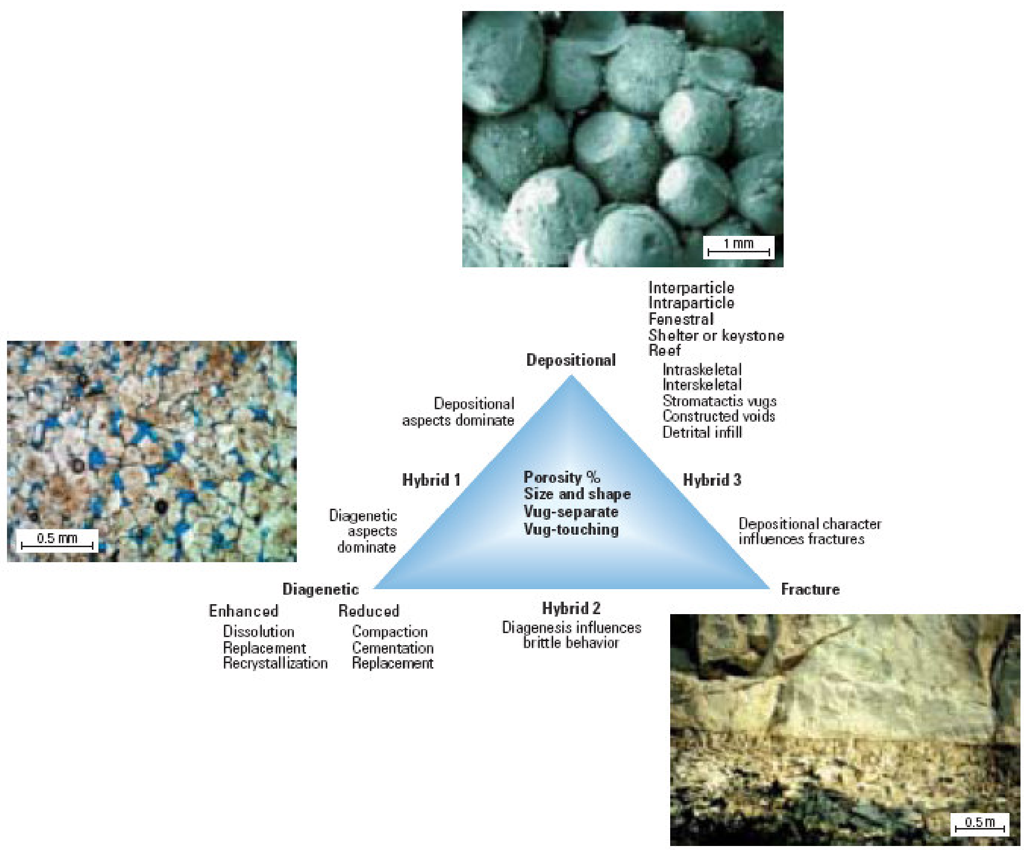

Figure 13. Ahr classification (Ahr, 2007).

In a simple network, spatial distribution of porosity is related to depositional facies boundaries but, because of the diagenesis, the modification of the porosity changes the prediction of the distribution. Understanding carbonate reservoir characterization leads to recognition of the different processes by which it is formed. As a consequence, the markers left some signs which is considered as rock properties by processes. Ahr (2007) wrote, "Knowing mode and time of origin for the markers, the spatial distribution of accompanying pore type can be predicted."

3.3.3. Explanation of the method

Considering the complicated or lack of interrelationship between permeability, porosity, and other reservoir properties, a new method was developed to define the reservoir quality.

This new method (called alternative method) uses the Ahr pore classification. The porosity is organized by type of porosity and classified by origin. On a permeability–porosity graph, each sample is plotted and identified according to its porosity.

In a second step, on this previous graph, equal lines corresponding to a ratio of K/Φ are plotted. The ratio of K/Φ determines potential barriers, baffles, and speed zones (Gunter et al., 1997).

CHAPTER IV

RESULTS

To date, most studies on reservoir characterization and evaluation have concentrated on identification of depositional facies because conventional methods have been based on the assumption that depositional characteristics govern reservoir properties. In sandstone reservoirs, that assumption is usually valid, but in carbonate reservoirs, it is not because the pore characteristics in carbonates vary depending on whether the pores are depositional and diagenetic (Martin, Solomon, and Hartmann, 1997a and 1997b). Other factors affecting pore characteristics include fracture or hybrid pore types (Ahr and Hammel, 1999; Ahr, 2005). As carbonate pore types vary depending on their mode of origin, their geometry – and their corresponding pore-throat geometry – also varies. This variability in pore and pore-throat characteristics is usually classified as "reservoir heterogeneity." Recent advances in methods to evaluate carbonate reservoir quality have focused on petrophysical measurements such as capillary pressure characteristics (e.g., Winland R35 method). From information in the literature, it can be suggested that the method is not very reliable for use in most carbonate reservoirs (Haro, 2004).

In this chapter, it will be shown that the R35 method is not usually a reliable method for use with carbonate reservoirs. First, the values of R35 will be calculated using MICP data and the Winland equation. The results of these two methods of calculation will be compared. Then, different interpretations of the R35 method will be tested on sample data from fields in the Smackover and Permian Formations. In a second part, the

Pittman method will be evaluated, and it will be shown that the "modal pore throat aperture" is also not a reliable method. The relationship between permeability, porosity, and pore throat radius is at minimum difficult to determine for most types of pores. Therefore, an alternative method is developed and applied to the same set of data as previously used. It will prove that to determinate reservoir quality, it is more reliable to use the genetic pore type (Ahr classification) instead of facies or rock type.

4.1. R35 CALCULATIONS ON SMACKOVER AND PERMIAN FORMATIONS

Recent advances in methods to evaluate carbonate reservoir quality have focused on petrophysical measurements such as capillary pressure characteristics. One such method was developed during the 1970s by H. K. Winland of Amoco Oil Company (Kolodzie, 1980). Winland defined R35 as the pore throat radius at which 35% of the pore and pore throat volume of a rock is saturated with non-wetting phase. This 35th percentile was taken to approximate the modal class of pore throat size where the pore network becomes interconnected, forming a continuous fluid path through the sample. Winland's original work included 82 samples of both carbonate (26) and siliciclastic (56) rocks corrected for gas slippage and 240 uncorrected samples with uncorrected permeabilities.

According to Hartmann and Coalson (1990), the R35 of a given rock type reflects both the depositional and diagenetic fabric and is directly related to permeability and reservoir performance. They tested this method in sandstone reservoirs only and found that of all samples examined, the best "quality" reservoir was the rock with pore–pore throat geometry indicated at the point where 36% of the pore–pore throat system was filled with the non-wetting phase. This essentially is the same result achieved by Winland (1978).

The Winland method (published by Kolodzie, 1980) is widely used to assess reservoir performance by determining the pore throat radius at 35% mercury saturation, a value that Winland posited to correspond to the optimum pore throat size, optimum porosity, and optimum permeability in the samples he measured.

This model appears to be more popular in the geosciences community (Haro, 2004). Because of its simplicity, this model is useful to assess reservoir performance (Martin, Solomon, and Hartmann, 1997b)

4.1.1. A test of the Winland R35 method using data from capillary pressure measurements from Smackover and Permian reservoirs in Texas and Alabama

R35 values represent the pore throat radius in microns, at 35% of non-wetting phase (mercury saturation). Pore throat radii are reported in MICP measurements from commercial laboratories (Table 3). The values are derived from calculations using the Washburn equation.

Table 3. R35 values from MICP (data from Petrotech Associates Lab)

Name	Porosity (%)	Permeability (md)	R35 (µm)
T 14078	4.33	0.40	0.89
t 11528	14.94	8.95	1.23
t 11413	15.30	8.83	1.50
t 11411	9.02	0.98	0.66
T 11405	19.60	35.30	2.58
T 11192	16.00	49.50	3.67
T 11515	16.40	34.67	2.80
T 11174	12.90	2.07	0.88
T 11156	15.90	7.19	1.43
T 11146	16.60	8.67	1.43
T 11129	18.70	17.83	2.24
4923.2	28.06	23.00	3.60
4956	45.70	18.04	1.14
4925	23.51	34.90	4.80
13016	16.35	108.00	4.60
T 12969	20.02	195.50	8.50
14144	8.11	10.70	8.30
12964	9.87	8.87	2.56
14087	17.28	64.52	6.69
T 12948	12.00	44.80	5.00
T 13024	4.14	17.60	9.05
T 12999	15.10	384.80	17.70
T 12984	16.70	225.40	11.80
T 12970	14.40	280.20	16.05
T 13946	9.65	86.70	10.19
14131	12.56	75.64	15.01
14150	15.47	111.00	11.41
12891,5	16.67	305.00	17.00
13014	16.79	144.00	12.80
T 13387	7.16	210.20	24.20
14017	5.32	7957.00	28.98

4.1.2. Reviewing the Winland equation and comparable alternative methods

In the absence of core data, R35 can be estimated directly from the Winland equation using permeability and porosity from routine core analyses. The Winland equation for R35 is: $\text{Log R35} = 0.732 + 0.588 (\text{Log } K_{air}) - 0.864 (\text{Log } \Phi)$. In the Winland equation, permeability (K_{air}) is given in millidarcies, porosity (Φ) is a percent value, and R35 is expressed in microns. K_{air} is the uncorrected air permeability. This equation is based on empirical data. Some authors (Pranter, 1999; Kolodzie, 1980) used multivariable linear regression to fit capillary pressure data and ultimately to modify the coefficients in the empirically derived Winland equation.

4.1.3. Comparison of R35 values obtained with the Winland equation and with MICP, interpreted by genetic pore categories in Smackover and Clearfork rocks

The Ahr genetic porosity classification is used in this section because Adams (2005) used this classification to describe these samples. He explained that this pore classification was an easier way to relate the observed pore types observed in thin section to the geological causes that formed them.

4.1.3.1. Diagenetic enhanced, intercrystalline pores

Intercrystalline porosity is purely of diagenetic origin. The size of the pore throats (Figure 14) in these samples is comparatively small. In this case, it is crystalline dolostones formed by replacement of limestone precursors. Dolomitization may preserve or, in some cases, increase the porosity.

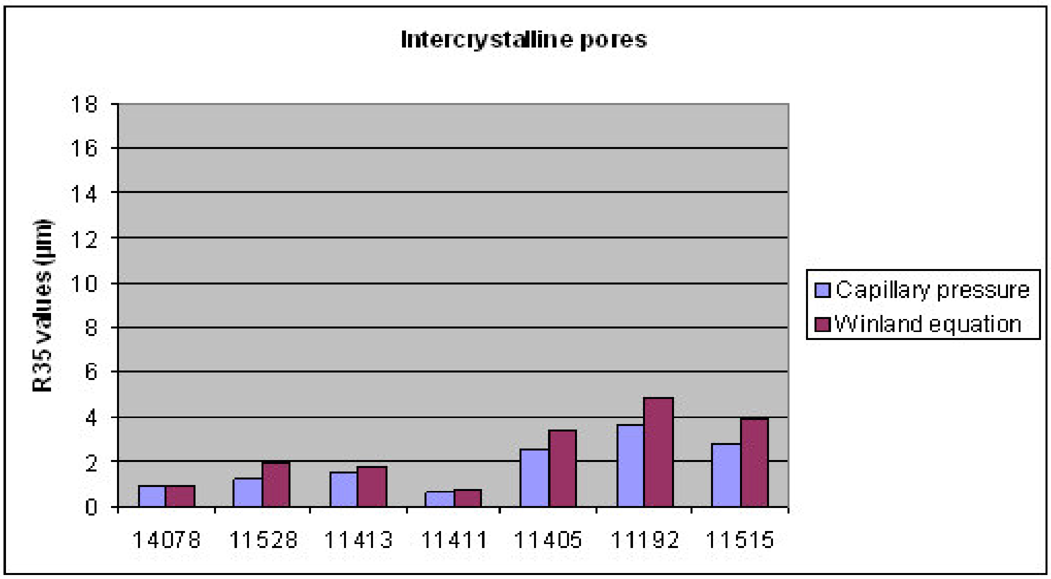

Figure 14. Comparison of R35 defined by capillary pressure and the Winland equation, applied to samples with intercrystalline porosity.

Values calculated from capillary pressure and from the Winland equation are quite similar. Therefore, either method can be used to calculate R35.

4.1.3.2. Hybrid 1 enhanced, moldic pores

These pores form from a combination of depositional and diagenetic processes. The size of the pore throat (Figure 15) is small.

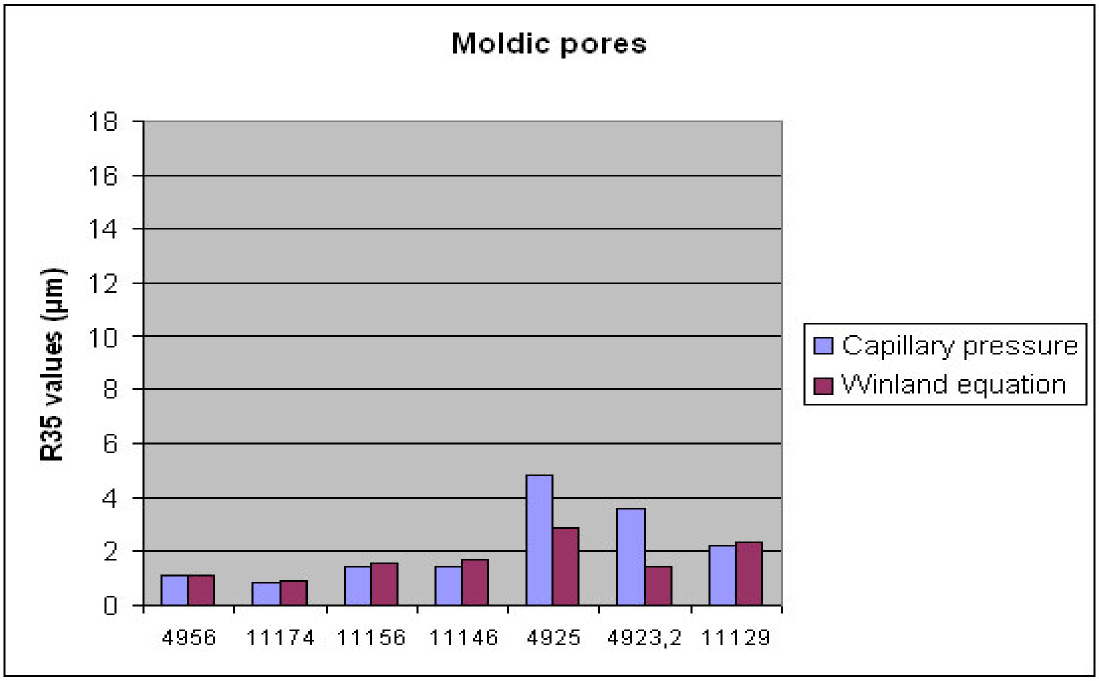

Figure 15. Comparison of R35 defined by capillary pressure and the Winland equation, applied to samples with moldic porosity.

R34 values calculated from capillary pressure and from the Winland equation are similar globally.

4.1.3.3. Hybrid 1-reduced, interparticle pores (small amount of cement)

Only two samples exhibited this type of pore (Figure 16). These are generally interparticle pores with minor amounts of cement around individual ooid grains. Both of the samples showed low porosity and very high permeability.

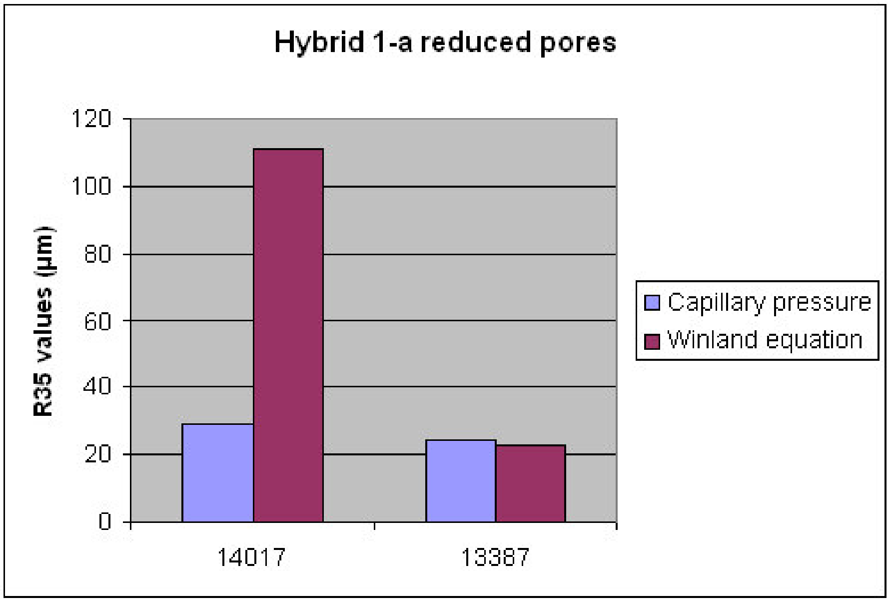

Figure 16. Comparison of R35 defined by capillary pressure and the Winland equation, applied to samples with small hybrid porosity.

Values calculated from capillary pressure and from the Winland equation are completely different for sample 14017. There are only two samples so no conclusion can be drawn as to why they differ.

4.1.3.4. Diagenetically enhanced, vuggy pores (touching and non-touching pores)

Vuggy porosity (Figure 17) is a hybrid of depositional and diagenetic processes, and it enhances porosity. Vugs may be touching or non-touching according to Lucia's (1983) classification of carbonate porosity. This type of pore system is heterogeneous.

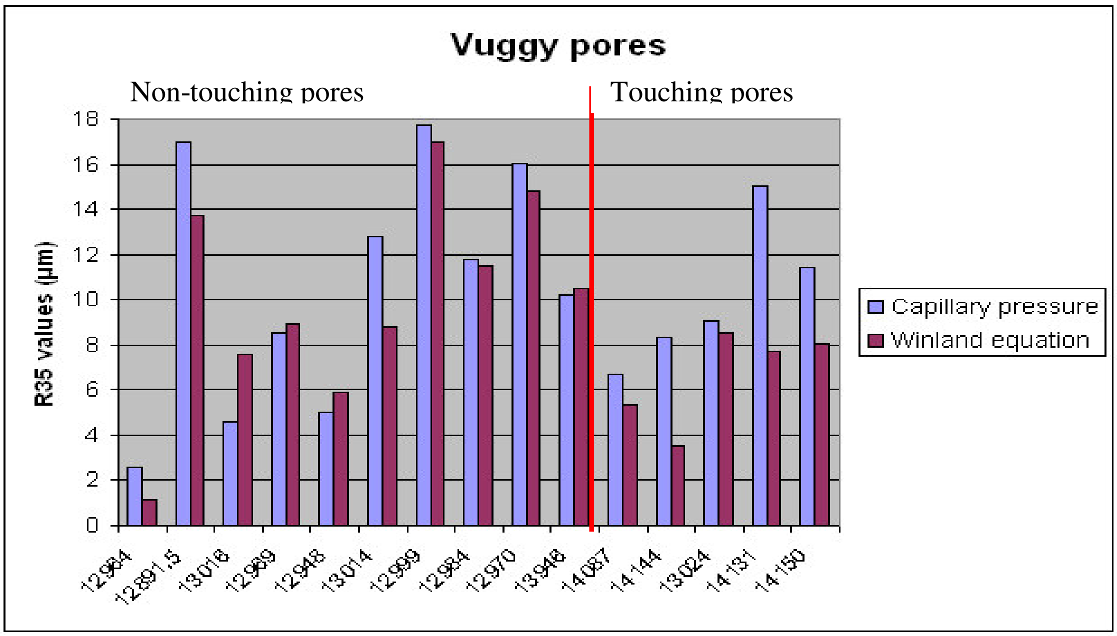

Figure 17. Comparison of R35 defined by capillary pressure and the Winland equation, applied to vuggy porosity samples.

The red line separates non-touching pores and touching pores. The R35 values calculated from capillary pressure data and from the Winland equation with porosity and permeability known are almost equal. For sample 14131, from Vocation/Appleton Fields, the R35 value calculated with MICP is twice as high as the value calculated with the Winland equation. R35 values from capillary pressure are always overestimated.

4.1.4. Results from comparison of the R35 values from MICP measurements and on calculations using the Winland equation

Comparison of the R35 values demonstrates that the heterogeneity of the pore system is a key factor when using the R35 method. For this reason, in the second part of this research, Ahr genetic pore classification is used instead of "facies" or "rocks," in a K/Φ plot, to test the alternative method. The R35 calculated with MICP and estimated from the Winland equation gives nearly the same result in interparticle pores with limited variability in pore–pore throat geometry. In carbonates, where that geometry is highly variable (hybrid, interparticle with small amount of cement and moldic pores), the R35 values from MICP can be twice as high as that calculated with the Winland equation.

The Winland equation has been used without changing the coefficients in the equation. These coefficients need to be fit to each reservoir because they are specific for each reservoir. On the other hand, the pore throat radius calculated from direct measurements of capillary pressure is a more reliable and deterministic method to define the reservoir quality. Even if capillary pressure data does not take into account branchiness (degree of bifurcation/connection among capillary tubes) and the tortuosity (winding characteristics) of the capillary tubes, the range of error is minimum.

4.2. INTERPRETATIONS OF THE R35 METHOD USING R35 VALUES FROM MICP

Some representative interpretations of the R35 method are tested on the data set and the results are given below.

4.2.1. Interpretation of Winland

A log-log porosity–permeability plot (Figure 18) based on R35 values from MICP has been created using 32 carbonate samples from the data set. The Winland R35 correlation cross-plot is shown in Figure 18.

The R35 lines based on Winland interpretation is applied.

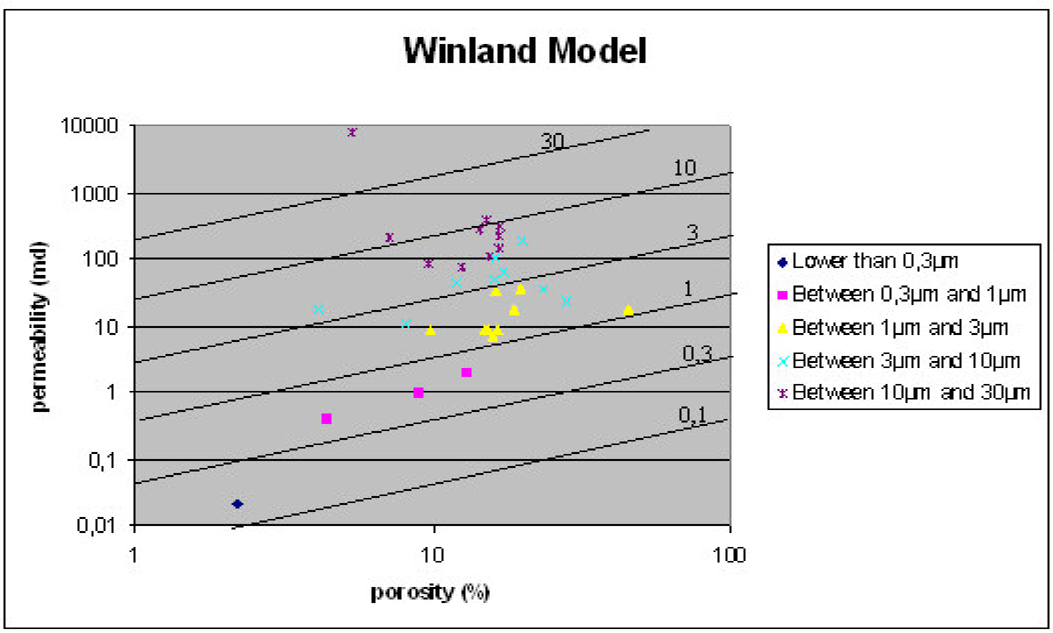

Figure 18. Interpretation from Winland of the permeability–porosity plot based on R35 values.

Winland (1978) divides pore throat sizes into the following categories: megaport (>10 µm), macroport (10–2 µm), mesoport (2–0.5 µm), microport (0.5–0.1 µm), and nanoport (<0.1 µm). Isopore–throat radius lines corresponding to values of 3–10 µm, 10–30 µm, and 30 µm of greater do not perfectly segregate pore throat radii of greater than 3 µm. It can be noted that these samples correspond to vuggy and hybrid 1a pores. For samples with intergranular porosity, the isopore–throat radius lines defined by Winland work very well, probably because the relationship between pore and pore throat size is more consistent than in the other types of pore (vuggy pores and hybrid 1a pores).

4.2.2. Significance of this observation

Another interpretation can be made from the data set. A general trend can be clearly seen in Figure 19; three R35 lines delineate four groups of pore throat radii.

The first isopore throat radius lines separate the sample with an R35 lower than 0.5 µm from the other pore throat radius points. The cut-off used for this first isopore throat radius is 0.5 µm. It is the same cut-off that Winland (1978) used in his study. The second group of pore throat radius at 35% of non-wetting phase saturation is located between isopore throat radius lines of 0.5 µm and 2 µm. Because in the petroleum industry 0.1 md is considered to be a cut-off to delineate very low permeability samples, the R35 lines, equal to 0.5 µm, stop at 0.1 md on the permeability axis. The third group of pore throat radius at 35% of non-wetting phase saturation is located between isopore throat radius lines of 2 µm and 10 µm. The fourth group corresponds to pore throat radius at 35% of non-wetting phase saturation greater than 10 µm. The standard deviation is the same between isopore R35 lines equal to 0.5 µm and 2 µm as between isopore R35 lines equal to 2 µm and 10 µm.

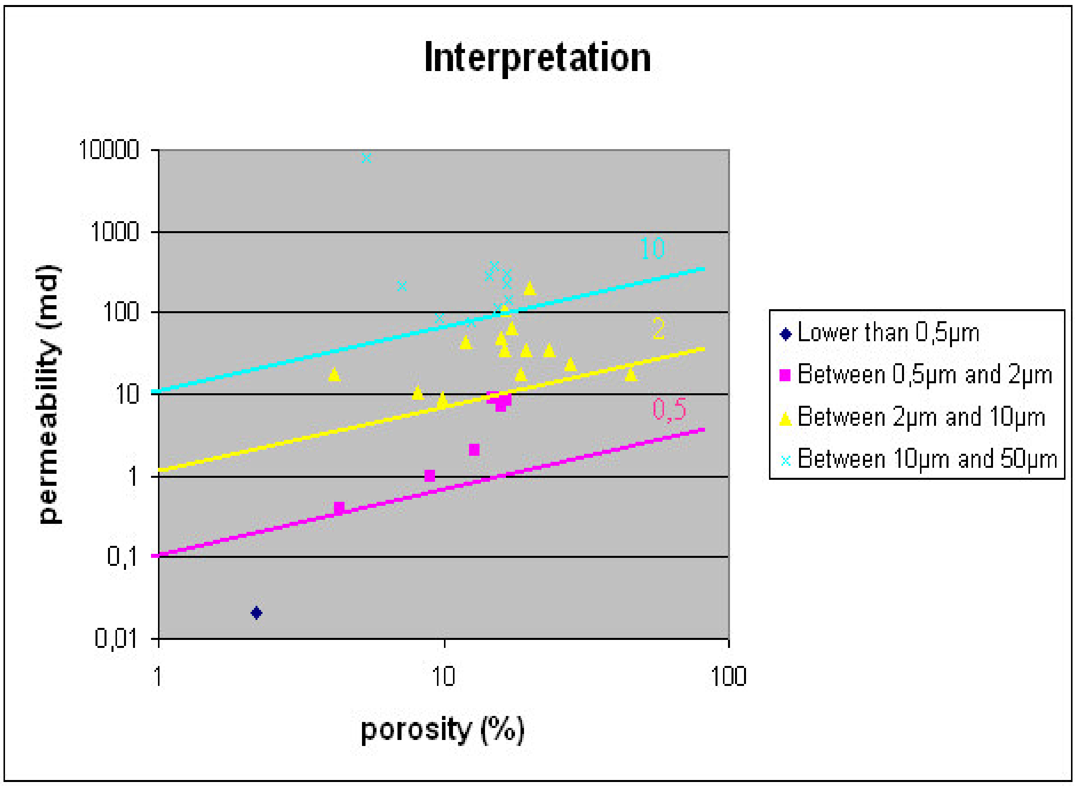

Figure 19. Interpretation of a permeability–porosity plot based on R35 values.

In general, a problem is encountered with the group of pore throat radii greater than 3 µm. No well-defined groups for this R35 can be made. This investigation demonstrated that there is a more or less accurate reproducible relationship between R35 and permeability. When the R35 value increases, so does permeability. The role of the porosity in the interpretation is minor up to 5%.

4.3. PITTMAN'S APEX METHOD

Katz and Thompson (1986) found that the point at which the MICP curve has an inflection on a capillary pressure plot corresponds to the modal pore throat size. Pittman (1992) developed equations to calculate pore aperture radii corresponding to mercury saturation values that range from 10% to 75% in increments of 5%. The Pittman equation for pore throat size at 35% non-wetting phase saturation (R35) is as follows:

$$\text{Log R35} = 0.255 + 0.565\ (\text{Log } K_{air}) - 0.523\ (\text{Log } \Phi)$$

In the Pittman R35 equation, permeability (K_{air}) is given in millidarcies, porosity (Φ) is in percent, and R35 is expressed in microns. K_{air} is the uncorrected air permeability.

4.3.1. Application

Using Pittman's method, which seems to be a more accurate graphic method (Haro, 2004), the apex (inflection point in mercury saturation versus mercury saturation–capillary pressure plot that describes the modal class of the pore throat size) is defined in Table 4.

Table 4. Average apex on carbonate data sample (porosity and permeability from Petrolab Associates Lab)

Apex	Pore Type	Porosity (%)	Permeability (md)
60	Dia-Enh (Intercrystalline)	9.02	0.98
64	Dia-Enh (Intercrystalline)	16.40	34.70
72	Dia-Enh (Intercrystalline)	15.00	8.95
76	Dia-Enh (Intercrystalline)	14.94	8.95
64	Dia-Enh (Intercrystalline)	19.60	35.30
66	Dia-Enh (Intercrystalline)	16.00	49.50
48	Dia-Enh (Intercrystalline)	4.30	0.40
38	Dia-Enh (Vuggy)	14.40	280.00
46	Dia-Enh (Vuggy)	15.10	385.00
32	Dia-Enh (Vuggy)	16.67	305
42	Dia-Enh (Vuggy)	16.79	144
46	Dia-Enh (Vuggy)	12.00	44.80
32	Dia-Enh (Vuggy)	9.87	8.87
50	Dia-Enh (Vuggy)	20.00	196.00
27	Dia-Enh (Vuggy)	16.70	225.00
42	Dia-Enh (Vuggy)	16.35	108
52	Dia-Enh (Vuggy)	9.65	86.70
35	Dia-Enh (Vuggy)	4.14	17.60
38	Dia-Enh (Vuggy)	17.28	64.52
40	Dia-Enh (Vuggy)	8.11	10.7
30	Dia-Enh (Vuggy)	12.56	75.637
52	Dia-Enh (Vuggy)	15.47	111
35	Dep/Hyb I-a	5.32	7957
37	Dep/Hyb I-a	7.20	210.00
48	Hyb I-b (moldic)	18.70	17.80
65	Hyb I-b (moldic)	16.60	8.67
56	Hyb I-b (moldic)	15.90	7.19
44	Hyb I-b (moldic)	12.90	2.07
64	Hyb I-b (moldic)	17.01	4.81
52	Hyb I-b (moldic)	23.51	34.9
40	Hyb I-b (moldic)	45.7	18.04
52	Hyb I-b (moldic)	28.06	23

As is seen in Table 5, there is a significant difference between the Winland R35 and the apex values defined graphically by pore type (Appendix).

Table 5. Average apex by type of porosity

Type of porosity	Number of samples	Average Apex
Intercrystalline	7	64
Vuggy	15	41
Hybrid 1b	2	36
Moldic	8	53
All porosity	32	48

The average apex of the hybrid 1b porosity, R36, is closed to the R35 determined by Winland. However, because there are only two samples in this category, the results are probably not significant. It is evident that the modal class of pore throat sizes varies for each type of porosity-and the pore types are unique to each reservoir. Additional work is needed to define modal class.

4.3.2. Pore throat size values defined by the apex method (Pittman, 1992)

After determining the apex, the corresponding pore throat aperture has been defined using MICP. This R(Apex), corresponding to the pore throat radius at the apex, describes the modal class of the pore throat size. To evaluate the validity of this method, a permeability–porosity plot related to the R(Apex) is shown in Figure 20.

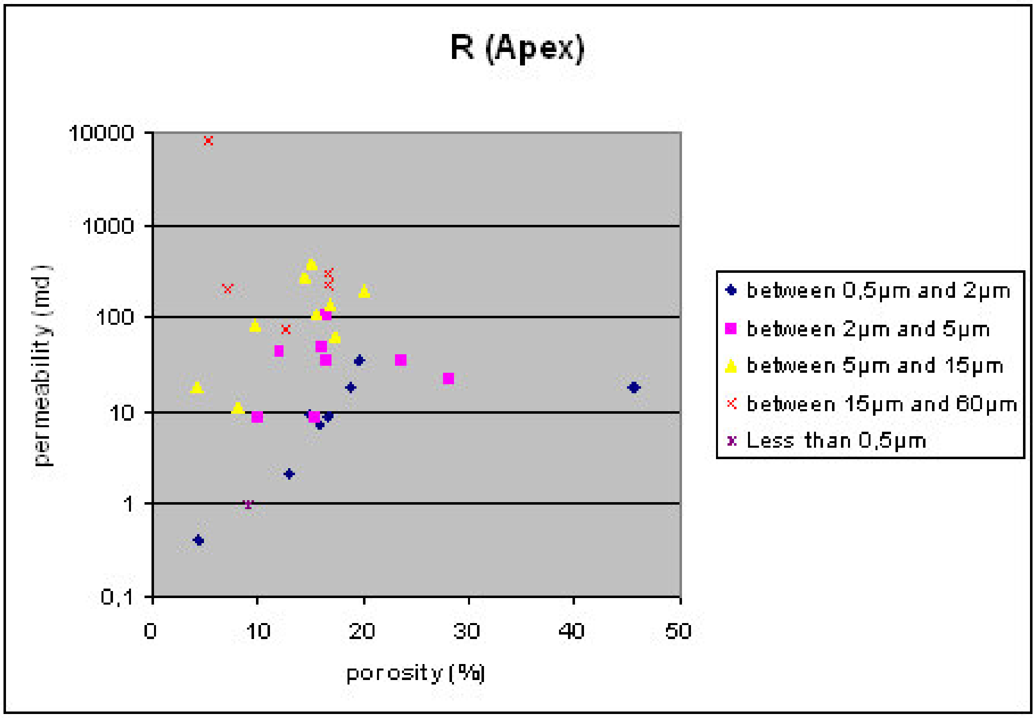

Figure 20. Permeability–porosity plot based on R(Apex) values.

No specific group of points is segregated in this graph. This plot confirms the results found using this apex method. The modal class of-pore throat sizes defined by the Pittman apex method is not a relevant parameter to evaluate a reservoir quality.

4.3.3. Comparison of the MICP, Winland and Pittman equations

The R35 values calculated with the Winland equation and with the Pittman equation are compared with the measured R35 calculated from direct measurements of MICP. The Pittman equation is derived from the Pittman graphic apex method (1992) and therefore is an improvement (Haro, 2004) on the Winland equation. Better results are expected from use of the Pittman equation compared with the R35 value derived from MICP.

All the samples have been classified by genetic pore type.

4.3.3.1. Diagenetically enhanced, intercrystalline pore (Figure 21)

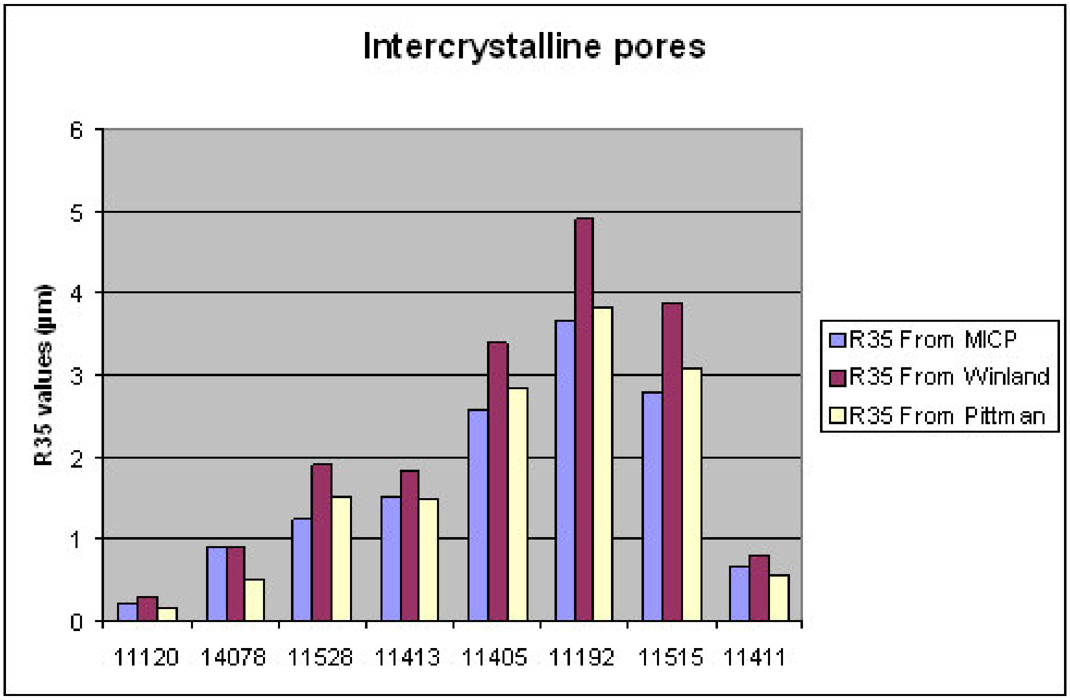

Figure 21. Comparison of R35 defined by capillary pressure, the Winland equation, and the Pittman equation, applied to samples with intercrystalline porosity

For all the interparticle pore samples, the R35 values (average: 1.4 µm) calculated with the Pittman equation are closer to the R35 (average: 1.93 µm) values measured with MICP compared to the value calculated with the Winland equation. R35 values from the Pittman equation are systematically lower than those from the Winland equation, but because the value of R35 is small, the differences between all the results areis very small.

4.3.3.2. Hybrid 1 enhanced, moldic pores (Figure 22)

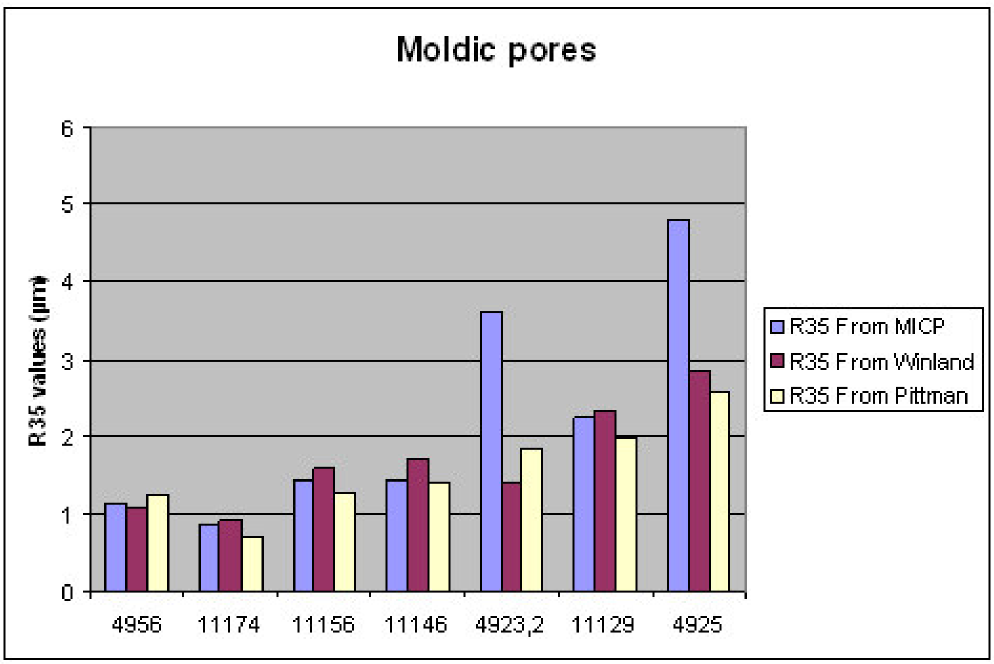

Figure 22. Comparison of R35 defined by capillary pressure, the Winland equation, and Pittman porosity, applied to samples with moldic porosity.

For these data, the R35 values from the Winland equation and the Pittman equation are the same.

The same situation applies for the two samples with a high R35 value from MICP. The pore throat radius from both equations is underestimated even if the scale is very small.

4.3.3.3. Diagenetically enhanced, vuggy pores (touching and non-touching pores) (Figure 23)

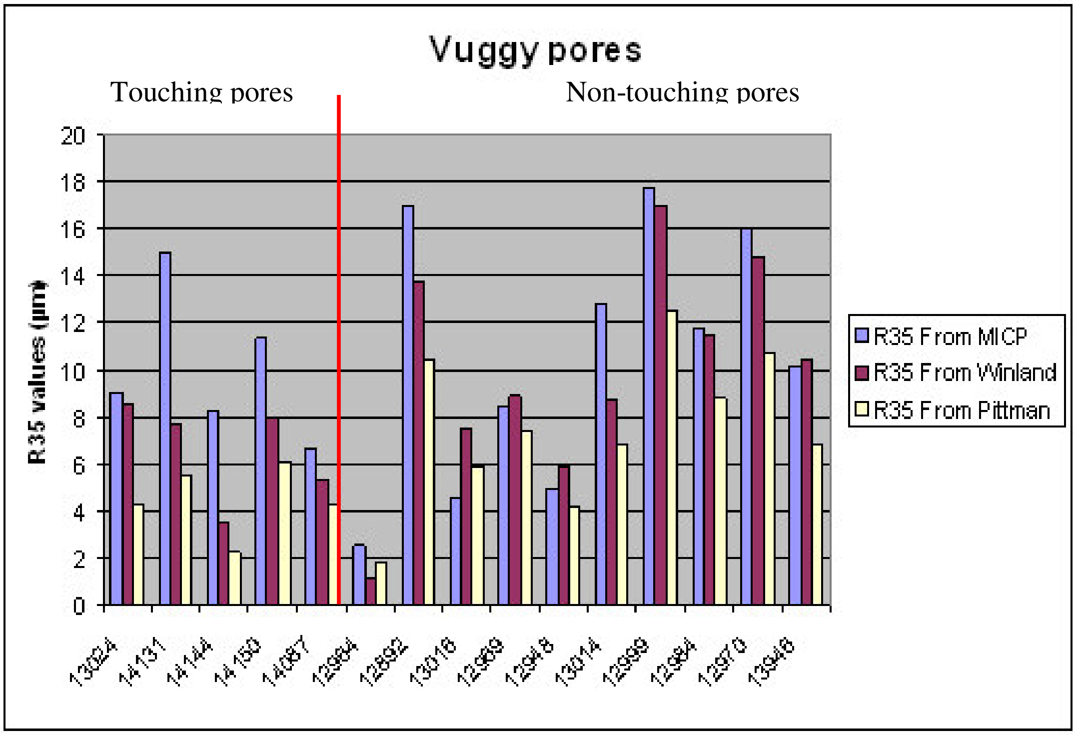

Figure 23. Comparison of R35 defined by capillary pressure, the Winland equation, and the Pittman equation, applied to vuggy porosity samples.

For either touching vugs or non-touching vugs, the value from use of the Pittman equation systematically underestimates values measured with MICP. The scale is large, and it can significantly affect quality estimates for the reservoir.

4.3.3.4. Hybrid 1-a reduced, interparticle pores (small amount of cement) (Figure 24)

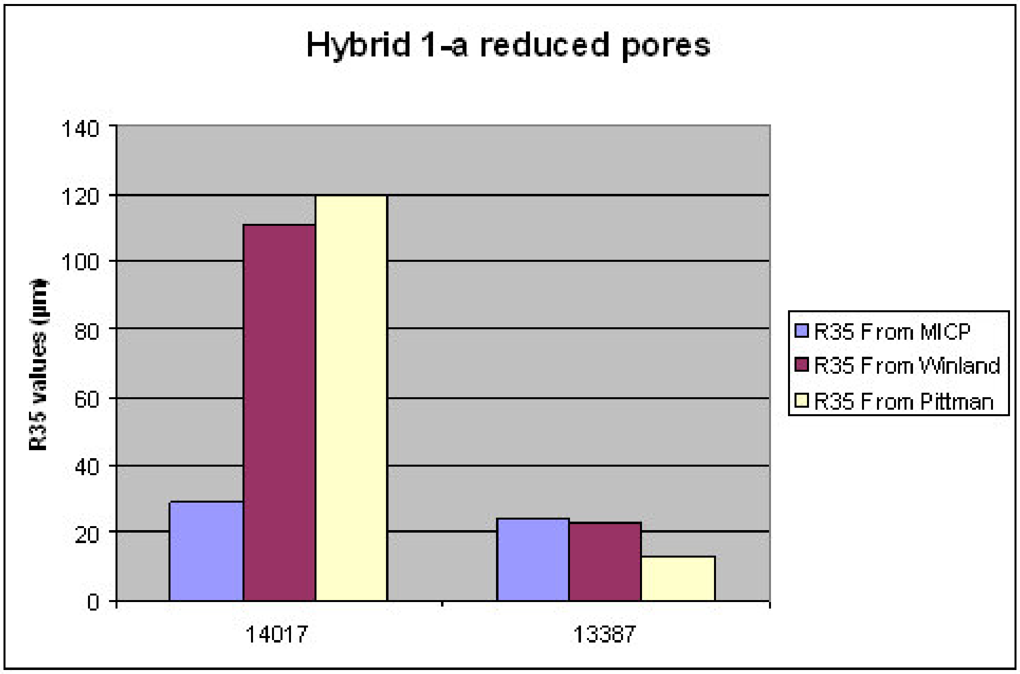

Figure 24. Comparison of R35 defined by capillary pressure, the Winland equation, and the Pittman equation, applied to samples with small hybrid porosity.

On sample 14017 from Vocation/Appleton Fields (Adams, 2005), the value calculated with either the Winland equation or the Pitman equation overestimates the value with MICP by a factor of 4. On the contrary, for sample T 13387, from Vocation/Appleton fields (Adams, 2005), the value calculated with the Pittman equation is half that calculated with MICP.

4.4. AN ALTERNATIVE SOLUTION TO THE R35 METHOD

In the previous chapter it was shown that using only one parameter (as pore throat radius R35) increases the possibility of error on complex carbonate reservoir evaluations. The R35 parameters cannot be used alone as a criteria for a flow unit in carbonate reservoir in many cases. The proposed alternative method uses the pore characteristics. Pore type is easy to define using a microscope and then pore type is defined by the Ahr classification (Ahr, 2005), a classification of pore types by geological origin.

4.4.1. Description of genetic pore types

In this set of data four different types of pores are defined (Figure 25): 1) intercrystalline pores, 2) vuggy pores, 3) moldic pores, and 4) hybrid 1-a reduced pores. These pore types were chosen by Adams (2005) using the Ahr 2005 classification because it was the easiest way to relate the final geological product (observed pores) to their pore-forming process (geological cause).

Table 6 provides a recapitulation of some parameters by type of pore.

Table 6. Recapitulation of some data by pore type

Pore origin	Pore type	Median pore aperture (µm)	Pore throat (µm)	Pore throat volume (%)
Hybrid 1 Enhanced (Dissolution)	Moldic	1.3–6.2	0.1–10	<10
Diagenetic Enhanced (dissolution)	Vuggy (touching)	7.6–20.3	1–100	< 5
	Vuggy (non-touching)	3.1–26.1	1–100	< 5
Diagenetic Enhanced (Replacement)	Intercrystalline	0.26–6.8	0.3–8.1	< 28
Hybrid 1a Reduced (cement)	Interparticle (small amount of cement)	1.3–6.2	0.1–10	< 10

Each pore type has been replaced on the triangular Ahr classification (Figure 25).

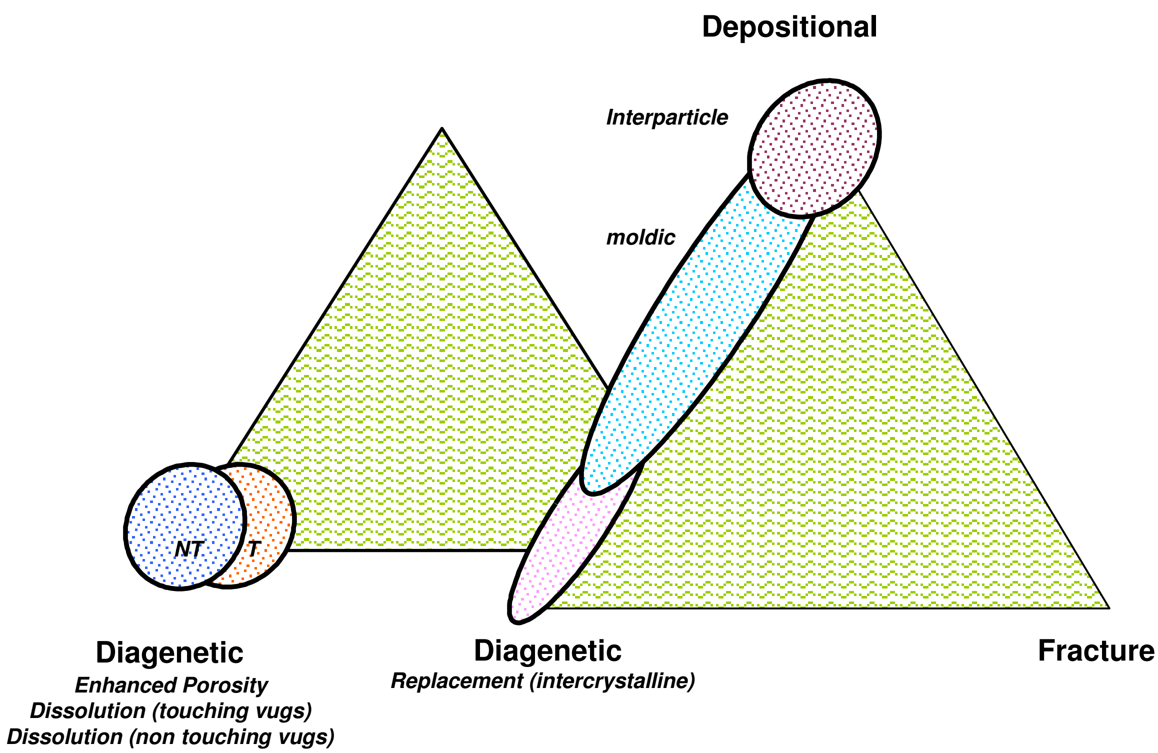

Figure 25. The place of each porosity in Ahr carbonate classification (modified from Adams, 2005).

4.4.2. The alternative method

A permeability–porosity plot based on pore geometry has been made. The relationship between porosity, permeability, and pore geometry (classified by genetic pore type based on Ahr classification) has been established (Figure 26).

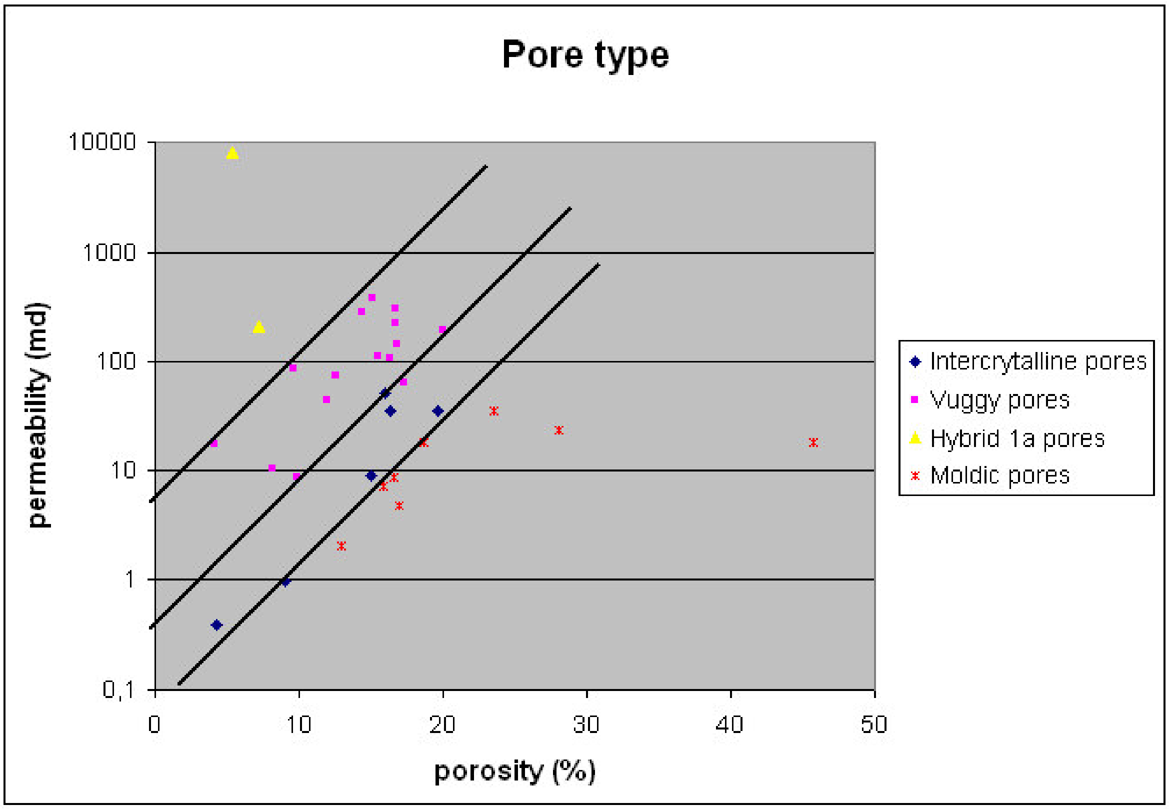

Figure 26. A permeability–porosity plot based on pore type according to Ahr classification.

To delineate the different porosities, an empirical equation was calculated to identify the characteristic pore geometry for intercrystalline samples.

$$y = 0.0734^{e\ 0.346x}$$

The R^2 of the equation corresponding to the line that delineates intercrystalline pores is equal to 0.898, this is a high correlation coefficient. A parallel line to this exponential line has been made to separates intercrystalline and vuggy porosity and also to separate intercrystalline and moldic porosity.

Because there is not much data for the delimitation between vuggy porosity and hybrid 1a porosity, it is difficult to determine accurate separation. Another parallel line to the exponential line defined previously was identified, but the exact location of this line to delineate these two groups was not determined by objective methods alone.

This graph is correlated to a permeability–porosity plot related to the ratio of K/Φ (Figure 27). The K/Φ relationship defines potential barriers, baffles, and flow units. K/Φ is often related to the Winland R35 equation. A low ratio shows some possible barriers or, at least, low-flow speed zones.

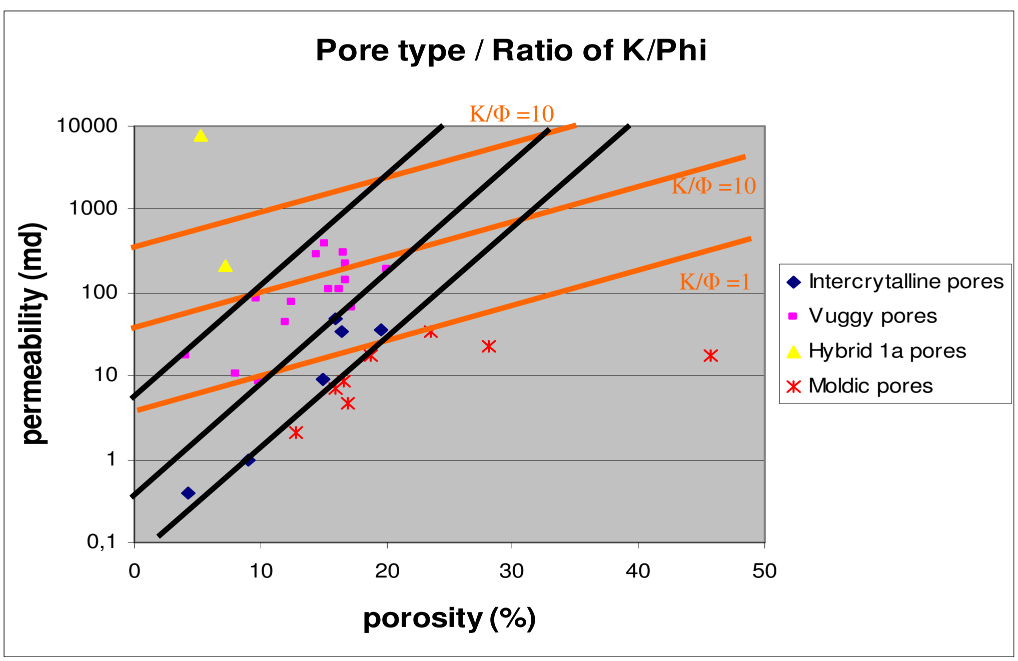

Figure 27. A permeability–porosity plot based on pore type (according to Ahr classification) and the ratio of K/Φ.

4.4.3. Interpretation

As can be seen from the graph, intercrystalline porosity appears to occupy a very limited area. Moldic porosity, on the other hand, occupies a wider area, presumably because of the diagenetic process, which enhances porosity and, to a lesser degree, permeability. Hybrid 1-a porosity and vuggy porosity points show high permeability even if the porosity is low. This K/Φ plot combined with the permeability–porosity plot based on pore type, according to Ahr classification, are good tools to evaluate a reservoir quality.

CHAPTER V

DISCUSSION

The Winland R35 method is not reliable for assessment of quality in carbonate reservoirs because of the heterogeneity of the pore system and because the relationship between porosity, permeability, and pore throat radius is not readily relatable to fundamental rock properties. An alternative method using genetic pore types provides better results.

5.1. RELATIONSHIP BETWEEN POROSITY, PERMEABILITY, AND PORE THROAT RADIUS IN CARBONATE RESERVOIRS

The previously discussed Winland R35 method is based on the assumption that there is a good relationship between porosity, permeability, and pore throat radius in all rock texture and fabrics.

5.1.1. R35 values: comparison

The R35 value corresponding to the pore throat radius at 35% mercury saturation (Table 7) was calculated using three different methods: MICP, Winland, and Pittman.

Table 7. Summary of R35 values from MICP report and the Winland and Pittman equations

Pore Origin	Pore type	R35 (µm)		
		MICP	Equation	
			Winland	Pittman
Hybrid 1 Enhanced (Dissolution)	Moldic	2,22	1,7	1,58
Diagenetic Enhanced (dissolution)	Vuggy (touching)	10,09	6,63	4,51
	Vuggy (non-touching)	10,62	9,97	7,56
Diagenetic Enhanced (Replacement)	Intercrystalline	1,93	2,23	1,74
Hybrid 1a Reduced (cement)	Interparticle (small amount of cement)	26,59	67,01	13,32

This study has revealed that Winland R35 values vary widely depending on which genetic pore types are involved in the calculations because genetic pore types generally have predictable pore–pore throat geometries and are not limited to depositional texture and fabric. For moldic and intercrystalline porosity, the R35 value is small and the difference is negligible. But for vuggy (touching and non-touching) and interparticle porosity, the difference in the calculated R35 value is twice as high as the measured MICP values.

Pittman's (1992) method does not produce much improved results (Table 8).

Table 8. Comparison of pore throat radius values

Pore Origin	Pore type	Pore throat radius (μm) at R35	Hg sat. At R(inflex)	Pore throat radius (μm) at R(inflex)	Pore throat radius difference
Hybrid 1a-b Enhanced (Dissolution)	Moldic	2,22	53	1,63	0,59
Diagenetic Enhanced (dissolution)	Vuggy (touching)	10,09	39	9,41	0,68
	Vuggy (non-touching)	10,62	41	9,36	1,26
Diagenetic Enhanced (Replacement)	Intercrystalline	1,69	64	1,67	0,02
Hybrid 1a Reduced (cement)	Interparticle (small amount of cement)	26,59	36	26,5	0,09

Even if mercury saturation values corresponding to R(inflex) (Pittman, 1992) are more reliable than values calculated with the R35 equation, the difference in terms of pore throat aperture is small because the R(inflex) is situated on the flat part of the capillary pressure curve.

5.1.1.1. Hybrid 1a-b enhanced, moldic pores

According to the Ahr (2005) classification, moldic pores are classified as hybrid 1a (depositional aspects dominate) to hybrid 1b (diagenetic aspects dominate). Moldic pore–pore throat connections depend on the rock matrix in which the molds are located

.

5.1.1.2. Hybrid 1a reduced or interparticle porosity with amount of cement

The original depositional porosity of these three samples was slightly reduced by post-depositional cementation and minor intraparticle dissolution (Adams, 2005). The modification of rock due to diagenesis changes the pore throat aperture, but the last one can be estimated by comparison if the sample is from the same pore category in the same stratigraphic interval as the others. The fact that R(inflex) is close to R35 has no significance; the small number of samples (two) is not representative of a population or distribution.

5.1.1.3. Diagenetically enhanced porosity related to dolomitization and attendant intercrystalline porosity. This porosity is formed by dolomitization (Figure 28), which is interpreted to have been important in the formation of pore shapes (Adams, 2005). The intercrystalline pores in this study represent the space between solids.

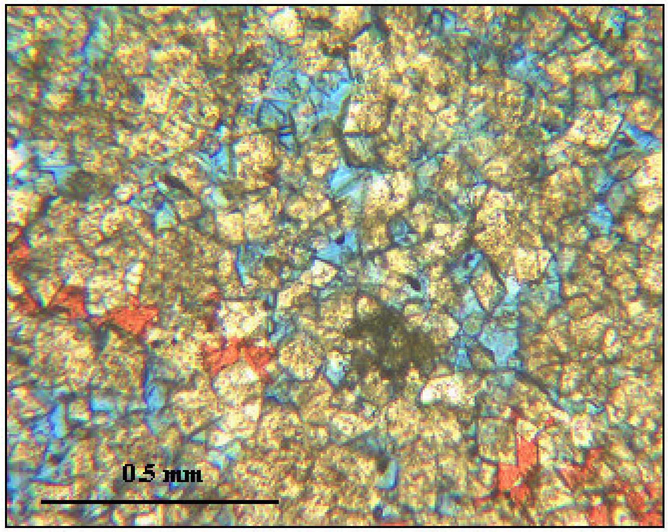

Figure 28. Intercrystalline porosity, dolomite crystals (Adams, 2005)

5.1.1.4. Diagenetic enhanced dissolution, vuggy porosity (non-touching pore and touching pore). This porosity occurs as a result of varying degrees of dissolution. Some samples exhibited vugs in combination with intercrystalline pores in dolomitized reef facies. Because of the dissolution, the size of the pores was increased but the pore throat aperture did not necessarily have corresponding increases in size. Consequently, the ratio of pore to pore throat sizes tends to increase.

5.1.2. General explanation

The R35 method doesn't work on carbonate reservoir. An explanation of the R35 method, which is based on facies rock, can be found using petrophysical characteristics of pores. According to the present study, R35 values calculated by the three methods from intercrystalline and moldic pores are more or less equal. It is not the case for vuggy and hybrid pores. For moldic pores, the relation pore–pore throat aperture depends on the matrix, so the R35 method is not reliable. Intercrystalline pores generally exhibit uniform pore and pore throat size distributions. On the contrary, vuggy, moldic, and hybrid porosity samples present a heterogeneous network with a tortuous pathway; consequently, the interconnected pore network is more tortuous and the pore throat distribution can differ with the same permeability. Diagenesis in carbonates affects the branchiness of the pore.

In conclusion, the R35 method is accurate in clastic reservoirs but not in carbonate reservoirs. The relationship between porosity, permeability, and pore throat aperture is not direct in carbonate reservoirs because of the heterogeneity of the rock. The R35 method or the apex method is based on the assumption that the pore network is almost homogeneous with a constant pore–pore throat ratio, but this ratio varies a lot and one of the reasons for this variation is the diversity of pore type. Due to the complexity of using this method, another one based on pore geometry and genetic pore type was developed.

5.2. THE ALTERNATIVE METHOD TO THE R35 METHOD

The alternative method is based on Ahr's genetic classification of porosity. Pores are defined by geological origin and related to pore geometry on thin sections: "Neglecting pore origin in mapping subsurface flow units can lead to erroneous correlations because diagenetic influences can persist across facies boundaries" (Adams, 2005).

The K/Φ ratio is an indicator of reservoir quality in terms of flow efficiency of a rock sample. If the ratio is low, the reservoir quality is poor. Table 9 combines pore type and K/Φ ratio.

Table 9. Determination of reservoir quality by the alternative method

<table>
<tr><th>Pore type</th><th>K/Φ ratio</th><th colspan="2">Percent type of pore</th><th>Quality</th></tr>
<tr><td rowspan="4">Moldic</td><td>< 1</td><td>100%</td><td rowspan="2">100%</td><td rowspan="4">Poor</td></tr>
<tr><td>1–10</td><td>0%</td></tr>
<tr><td>10–50</td><td>0%</td><td rowspan="2">0%</td></tr>
<tr><td>> 50</td><td>0%</td></tr>
<tr><td rowspan="4">Intercrystalline</td><td>< 1</td><td>50%</td><td rowspan="2">100%</td><td rowspan="4">Poor</td></tr>
<tr><td>1–10</td><td>50%</td></tr>
<tr><td>10–50</td><td>0%</td><td rowspan="2">0%</td></tr>
<tr><td>> 50</td><td>0%</td></tr>
<tr><td rowspan="4">Vuggy</td><td>< 1</td><td>0%</td><td rowspan="2">65%</td><td rowspan="4">Intermediate</td></tr>
<tr><td>1–10</td><td>65%</td></tr>
<tr><td>10–50</td><td>35%</td><td rowspan="2">35%</td></tr>
<tr><td>> 50</td><td>0%</td></tr>
<tr><td rowspan="4">Hybrid 1a</td><td>< 1</td><td>0%</td><td rowspan="2">0%</td><td rowspan="4">Good</td></tr>
<tr><td>1–10</td><td>0%</td></tr>
<tr><td>10–50</td><td>50%</td><td rowspan="2">100%</td></tr>
<tr><td>> 50</td><td>50%</td></tr>
</table>

This table shows that purely diagenetic pores and diagenetically enhanced pores correspond generally to good reservoir quality.

CHAPTER VI

CONCLUSIONS

- R35 method is a good method to determine reservoir with unaltered intergranular porosity.
- The apex method of Pittman (1992) indicates that there is no linear relationship between porosity, permeability, and pore throat radius in complex pore networks.
- An alternative method based on the genetic classification of carbonate porosity by Ahr (2005) shows a direct link between porosity, permeability, and genetic pore type when pores are classified according to the Ahr system.
- The ratio of K/Φ combined with the Ahr porosity classification yields reliable results for discriminating between baffles, barriers, and flow units.
- Petrophysical rock types based on genetic pore categories—and their associated pore and pore throat geometries - provide much more reliable results about assessing flow unit quality than methods based on facies like the Winland plot, the Lucia rock types, and the Pittman method.

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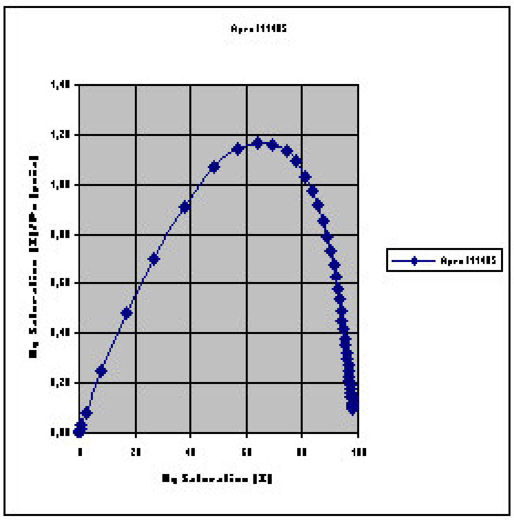
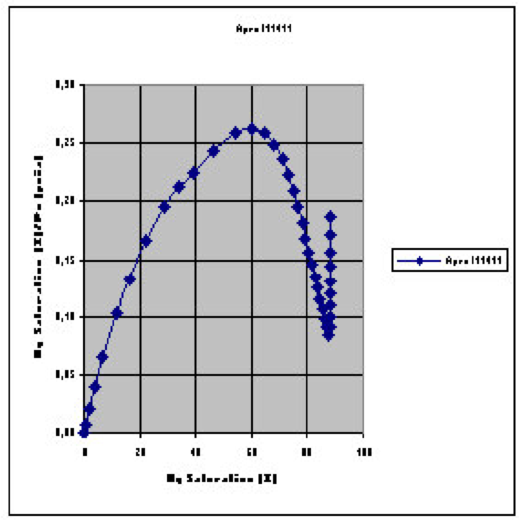
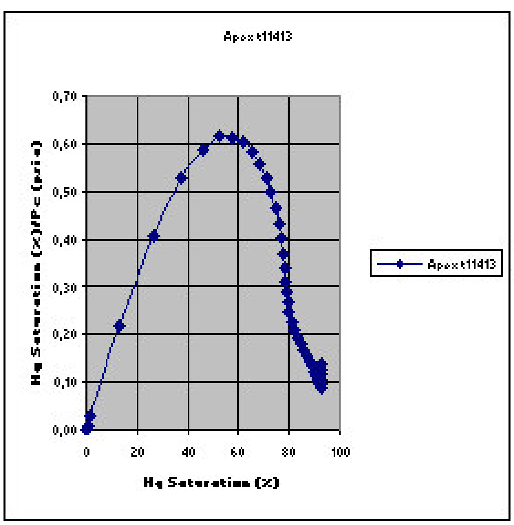
APPENDIX

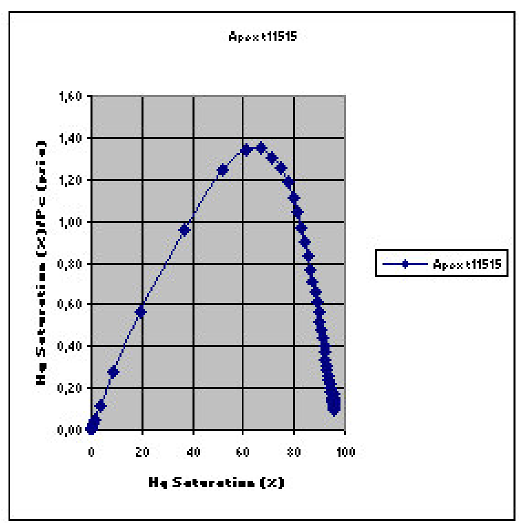
GRAPH APEX

Diagenetic (Intercrystalline pores)









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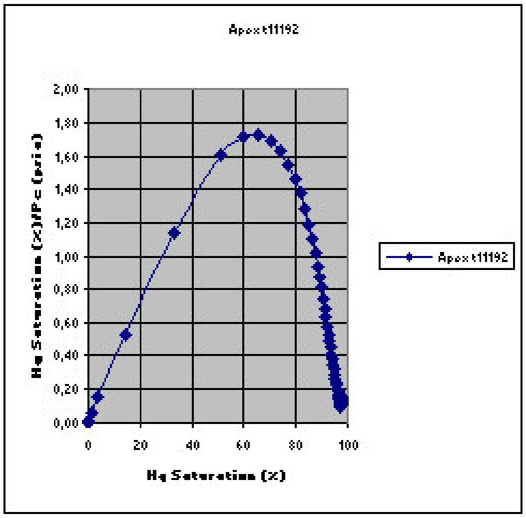
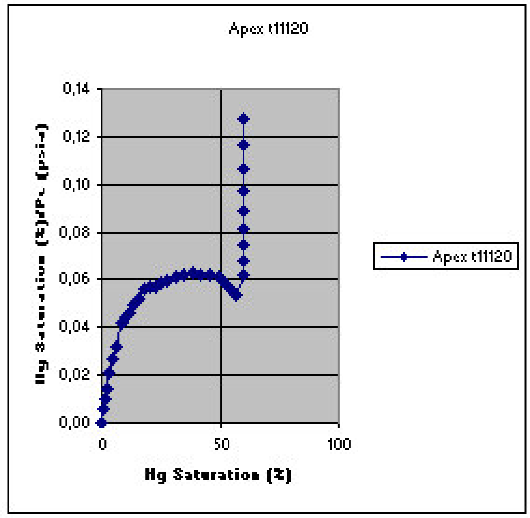
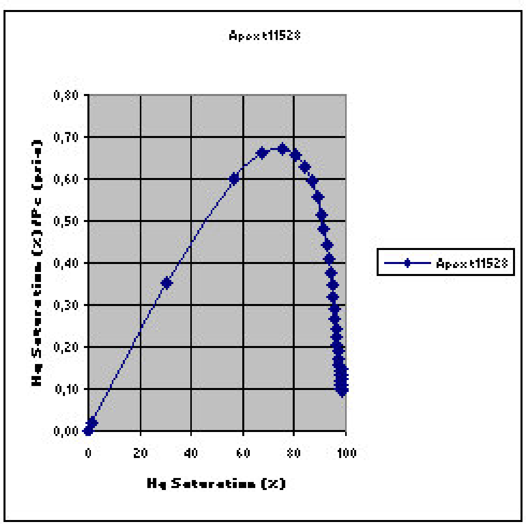
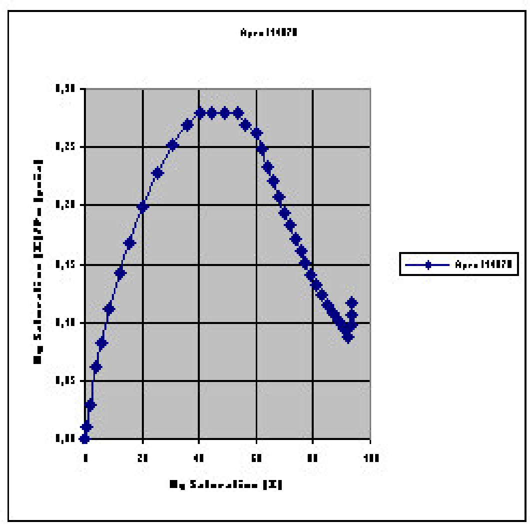
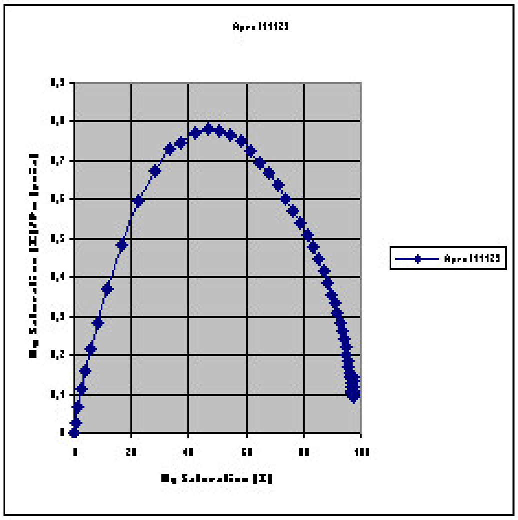


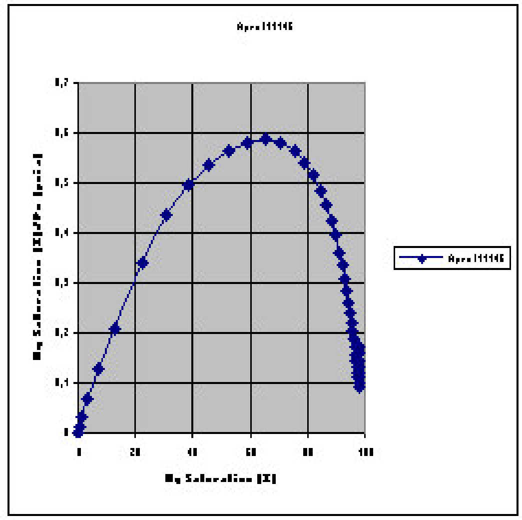


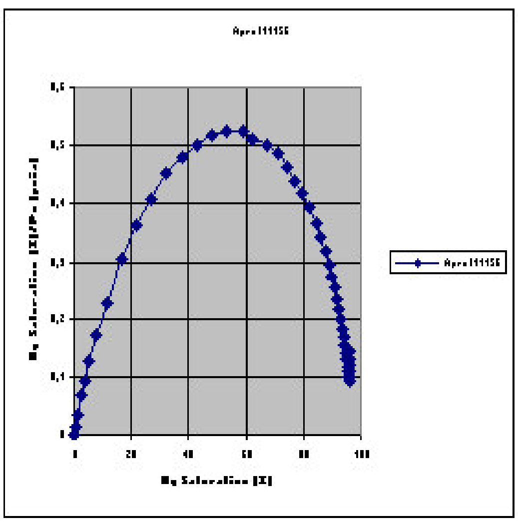


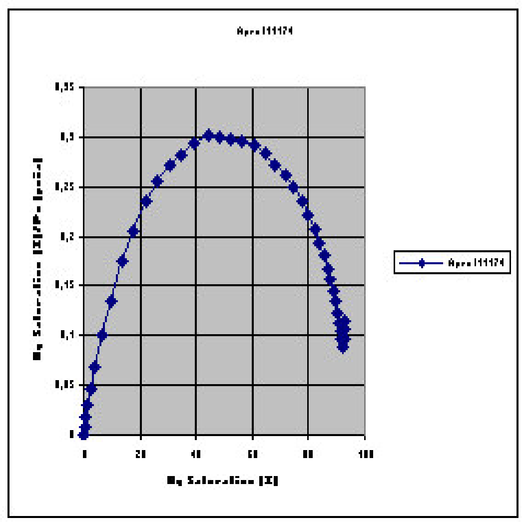


Hybrid 1 (Moldic pores)









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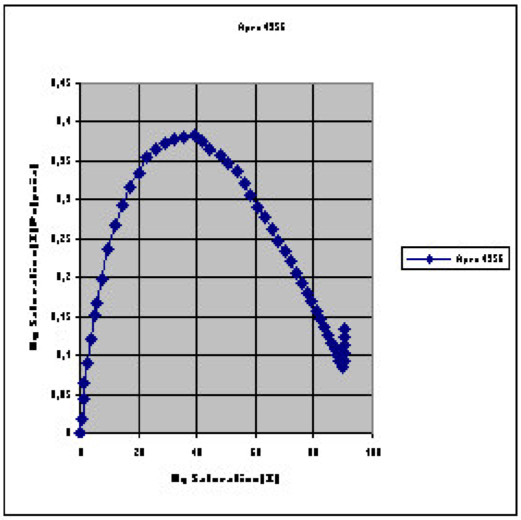
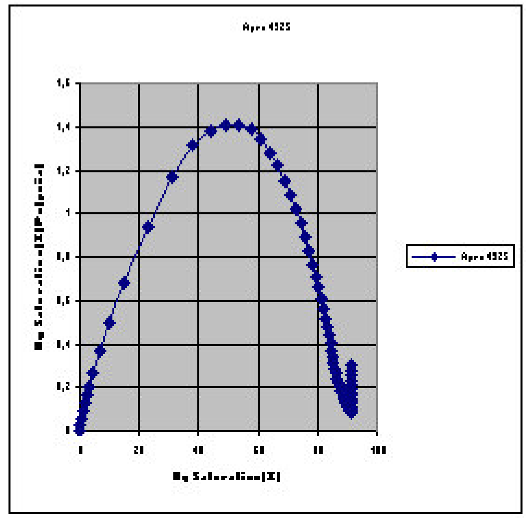
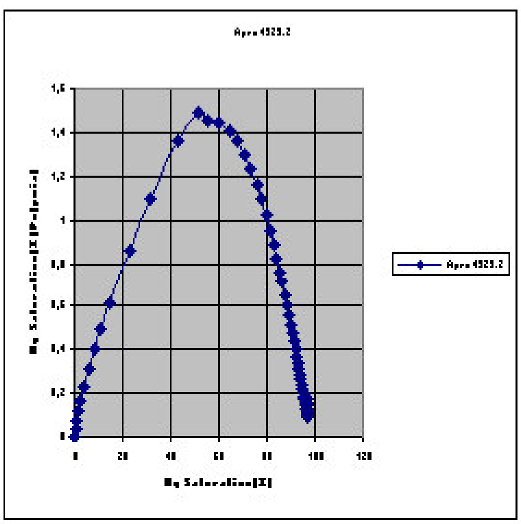
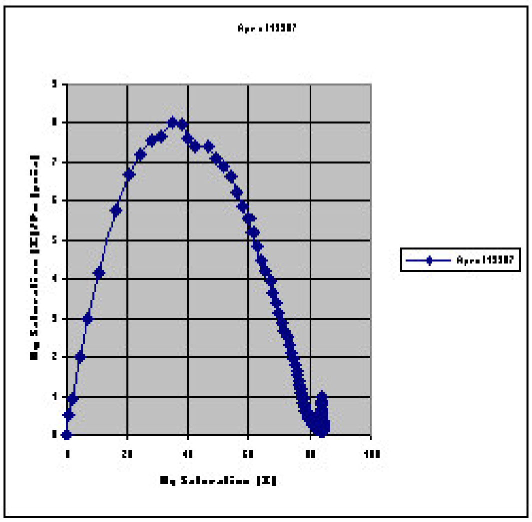
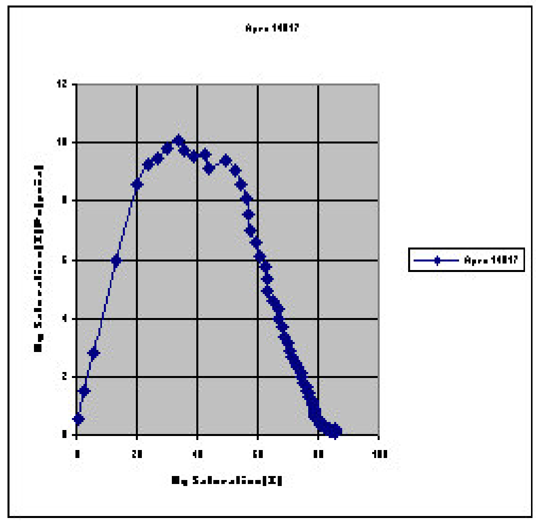




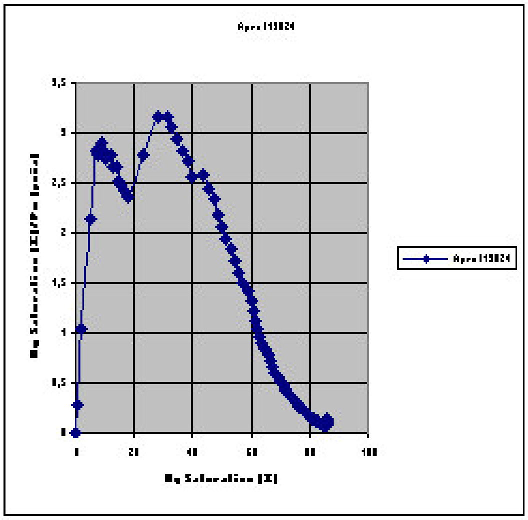


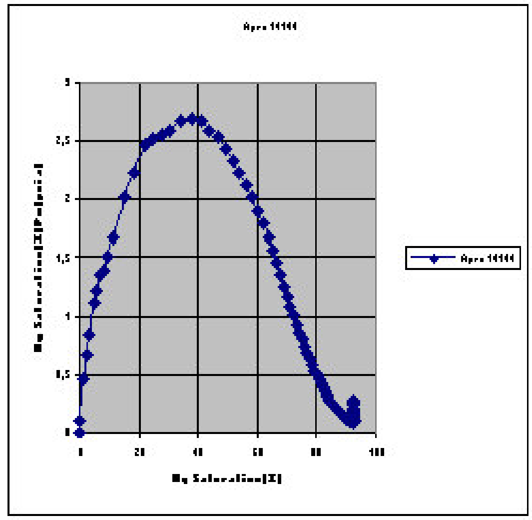
Hybrid 1-a (Interparticle with small amount of cement)

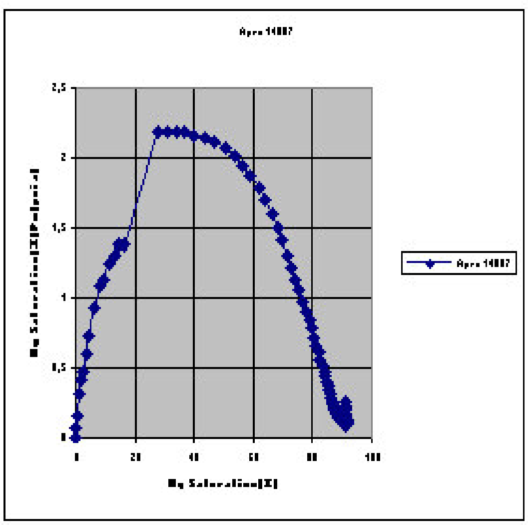


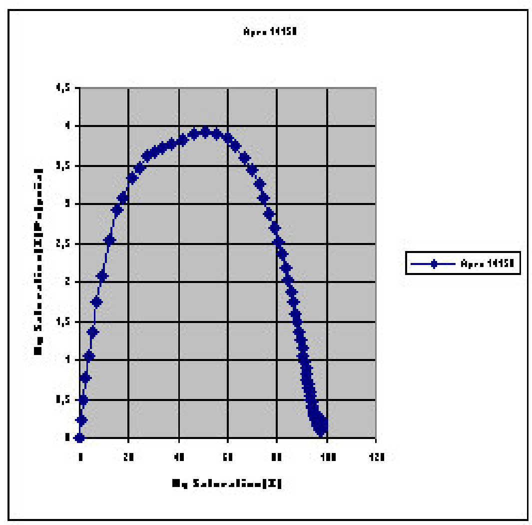


Diagenetic-Enhanced porosity (Vuggy Touching)









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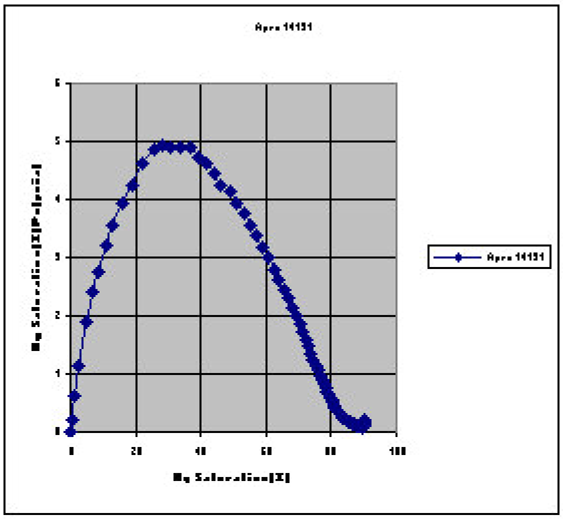

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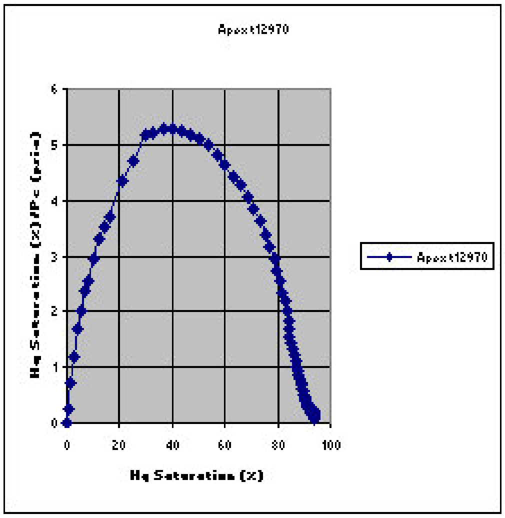

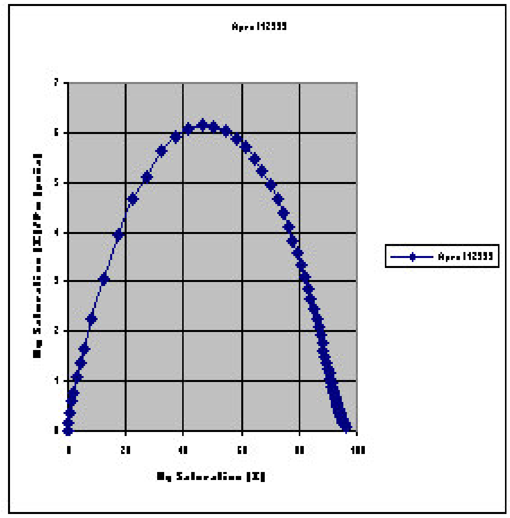

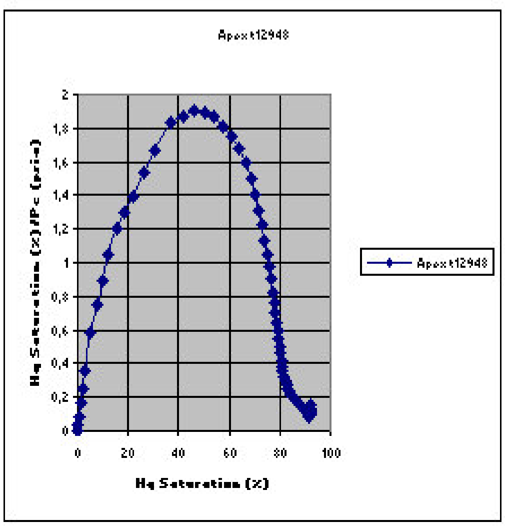

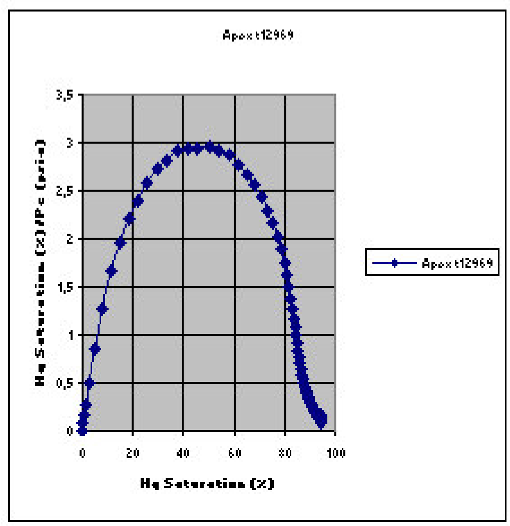

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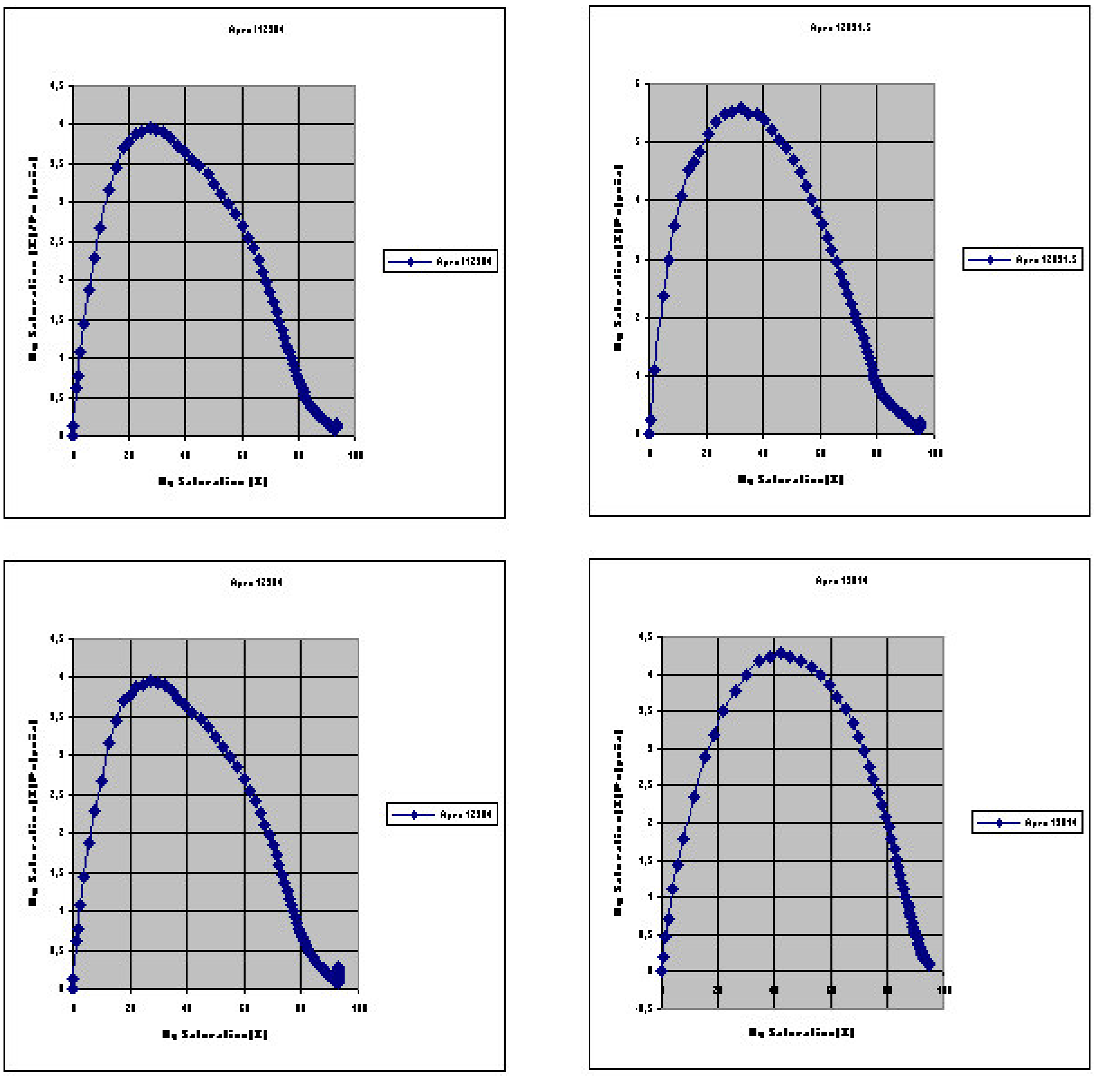

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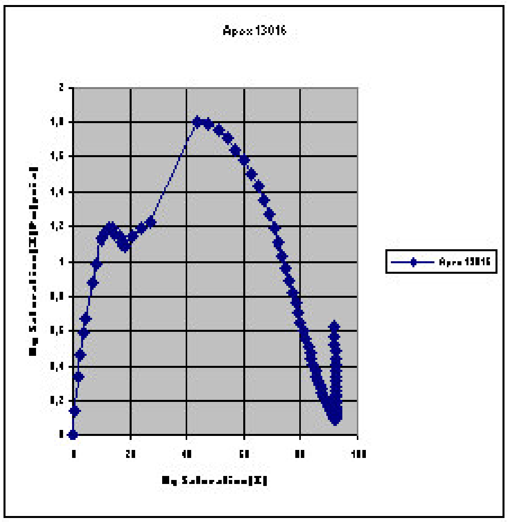

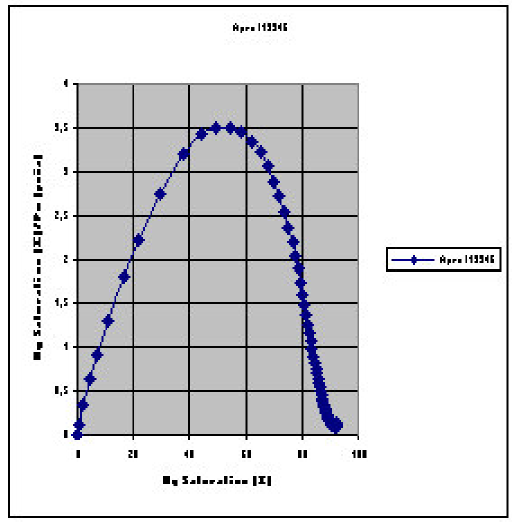

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